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

FORM 40-F

[Check one]

¨ **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, 2013 **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))

2845 Bristol Circle
Oakville, Ontario
L6H 7H7, 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, 2013, there were 206,348,985 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** ¨

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** ¨

ANNUAL INFORMATION FORM

The Annual Information Form of Algonquin Power & Utilities Corp. ("Algonquin") for the fiscal year ended December 31, 2013 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, 2013 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, 2013 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 60) 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, 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, 2013, based on the framework established in Internal Control- Integrated Framework (1992) 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, 2013.

During the year ended December 31, 2013, Algonquin acquired Shady Oaks Holdings, TianRun Shady Oaks LLC, GSG6 LLC, Liberty Utilities (Pine Bluff Water) Inc., Liberty Utilities (Peach State Natural Gas) Corp. and Liberty Utilities (New England Natural Gas Company) Corp. As of December 31, 2013, these acquired entities represent 16% of total assets and represent 10% and 17% of revenue and earnings from continuing operations before income taxes, respectively, for the year then ended. As permitted by the U.S. Securities and Exchange Commission, Management excluded these acquisitions from its evaluation of the effectiveness of the Company's internal controls over financial reporting as of December 31, 2013 due to the complexity associated with assessing internal controls during integration efforts and the proximity of certain of the acquisitions to year-end.

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, 2013, has also issued an attestation report on the effectiveness of Algonquin's internal control over financial reporting as of December 31, 2013.

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, 2013, 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 60) 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, 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 George Steeves 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 George Steeves 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 George Steeves 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., 2845 Bristol Circle, Oakville, Ontario, L6H 7H7.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information provided under the heading “Pre-Approval Policies and Procedures” (page 104) in 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, is incorporated by reference herein. All audit services, audit-related services, tax services, and other services provided for the year ended December 31, 2013were 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 45) 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, is incorporated by reference herein.

IDENTIFICATION OF THE AUDIT COMMITTEE

The information provided under the heading “Audit Committee” (page 103) 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, 2013, 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, 2013 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 28, 2014

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, 2013
99.2	Audited Annual Financial Statements for the year ended December 31, 2013
99.3	Management's Discussion & Analysis for the year ended December 31, 2013
99.4	Consent Letter from KPMG LLP, Chartered Accountants
99.5	Consent Letter from Ernst & Young LLP, Chartered Accountants
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ALGONQUIN POWER & UTILITIES CORP.

ANNUAL INFORMATION FORM

March 28, 2014

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All information contained in this Annual Information Form ("AIF") is presented as at March 28, 2014, 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 earnings before interest, tax, depreciation and amortization (“EBITDA”) and “adjusted funds from operations” are used in this Annual Information Form. The terms EBITDA and “adjusted funds from operations” are not recognized measures under GAAP. There is no standardized measure of EBITDA or “adjusted funds from operations”. 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 EBITDA and “adjusted funds from operations” can be found in APUC's most recent Management's Discussion & Analysis.

Use of Non-GAAP Financial Measures

EBITDA

EBITDA is a non-GAAP metric 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 EBITDA to assess the operating performance of APUC without the effects of: depreciation and amortization expense, income tax expense or recoveries, and interest expense. APUC adjusts for these factors as they may be non-cash, 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. 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 metric 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. 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.

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 Societe 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 APCo (the "**Unit Exchange**") and changed its name to Algonquin Power & Utilities Corp. The head and principal office of APUC is located at 2845 Bristol Circle, Oakville, Ontario, L6H 7H7. APUC contemporaneously acquired all of the outstanding trust units of Algonquin Power Co.

APUC's principal holdings are its direct ownership of trust units ("**Trust Units**") of APCo and its indirect ownership of the shares of Liberty Utilities Co. through an ownership chain as described below.

Unless the context indicates otherwise, references in this AIF to "**APUC**" 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**" 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

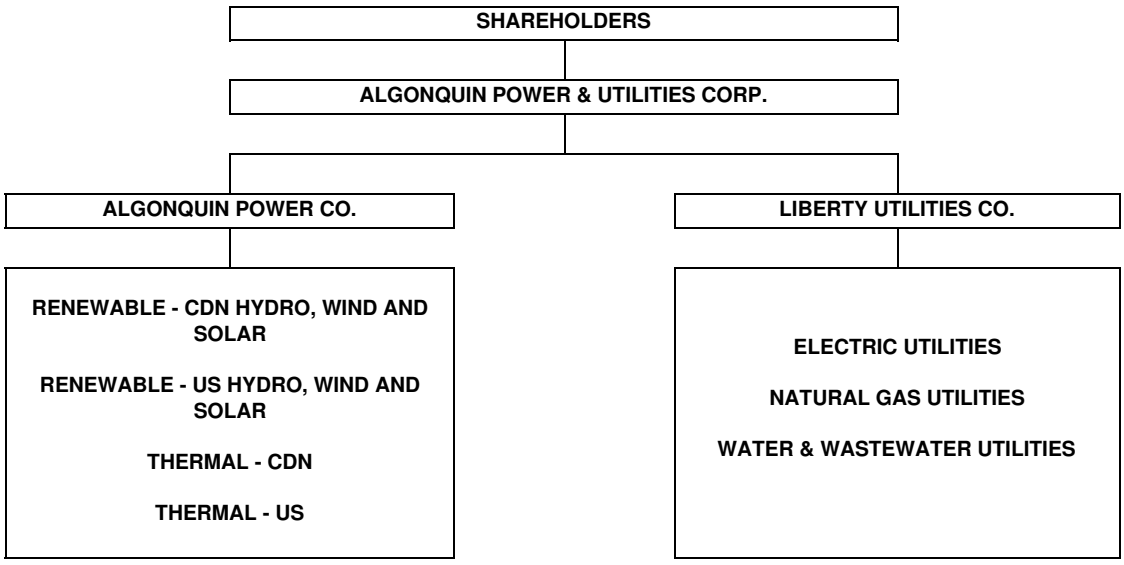
(a) **Subsidiaries**

The subsidiaries of APUC are grouped into the independent power generation and the utilities businesses. The principal holding for APUC's independent power generation business is an investment in 100% of the issued and outstanding Trust Units of APCo. The principal holding for APUC's utilities business is an investment in 100% of the issued and outstanding common shares of Liberty Utilities (Canada) Corp. ("LU Canada"), a federal corporation, which in turn owns all of the issued and outstanding common shares of Liberty Utilities (America) Co., a Delaware corporation, which in turn owns all of the issued and outstanding common shares of Liberty Utilities (America) Holdco Inc., a Delaware corporation, which in turn owns all of the issued and outstanding shares of Liberty Utilities, a Delaware corporation, which in turn owns the utility subsidiaries. Both of APCo and Liberty Utilities have their own subsidiaries and ownership chains.

The subsidiaries of APCo include the ownership chains of Algonquin Power Trust, and Algonquin Power Fund (Canada) Inc.. APT's subsidiaries include the ownership chain of Algonquin Power Operating Trust, and APFC's subsidiaries include the ownership chain of Algonquin Power Fund (America) Inc.. 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 through its subsidiary, Liberty Utilities

(Sub) Corp., has investments in water distribution and wastewater collection utility systems in Arizona, Texas, Illinois, and Missouri.

The following chart summarizes the principal operating subsidiaries of the Corporation and their major lines of business.



The major chains are defined below, including a detailed description of 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) **Independent Power Generation Business – APCo Chain**

APCo Chain Entities

APCo is the sole beneficiary of APT. APCo also owns Algonquin Holdco Inc., an Ontario corporation, which owns 74.96% of APFC. Also, APCo owns 62.5% of the issued and outstanding shares of Cornwall Solar Inc., 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, and indirectly owns the energy-from-waste facility (the "**EFW Facility**") located in the Regional Municipality of Peel, Ontario by virtue of owning all 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., an Ontario corporation that owns the EFW Facility. APFC owns the outstanding preferred shares of APEFW.

APT also holds interests in certain of APCo's Canadian hydroelectric generating facilities. It directly owns the hydroelectric 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 directly owns a 42% 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 58% partnership interests, comprised of a 46.5% limited partnership interest and an 11.5% general partnership interest.

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 Canadian cogeneration facility located at Brampton, Ontario (the '**BCI Thermal Facility**"). The BCI Thermal Facility is owned by Brampton Cogeneration Limited Partnership, an Ontario partnership, the partners of which are Brampton Cogeneration Inc., which is the general partner and holds one general partnership unit, and APOT, which owns 100% of the Class A Units (entitled to vote on all matters) and 50% of the Class B Units (entitled to vote only on specific matters) in the limited partnership, APFC owns the remaining 50% of the Class B units. BCI is an Ontario corporation and is owned by APOT.

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 holds a 25.04% interest in APFC. 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.

APFC Group

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

In Ontario, APFC directly owns the Burgess and Hurdman Hydro Facilities, and has an agreement in place to buy ownership interests in the parties to the joint venture that owns the interests in the Long Sault Hydro Facility. 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 interst in the St. Alban Hydro Facility. APFC also holds a direct interest in Société Hydro-Donnacona, 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 APFC and 0.01% by Donnacona Holdings Inc., an Ontario corporation 100% owned by APFC. APFC also owns 100% of Algonquin Power Services Canada Inc., a Canadian corporation that provides purchasing services to Canadian APCo entities.

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

On January 1, 2014, APFC completed the purchase of Algonquin Power Corporation Inc., an Ontario corporation formerly owned by various private holding companies. By virtue of this acquisition, APFC came to indirectly, wholly owning a 99.9% general partnership interest in Algonquin Power (Long Sault) Partnership, an Ontario general partnership which is a 50% partner in the Long Sault Hydro Facility. APCI also 100% owns Algonquin Power (Long Sault) Corporation Inc., an Ontario corporation which is the general partner, holding a 0.1% general partnership interest, in the LS Partnership.

Through the above mentioned acquisition, APFC also came to indirectly, wholly own APCI's 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.

Concurrent with the closing of the APCI purchase, APFC also divested its 45% interest in the Algonquin Power (Rattlebrook) Partnership which owns the Rattlebrook hydro facility in Newfoundland

APFA Group

APFA, a Delaware corporation, is owned by APA (100% common shares) and its parent APFC (100% Series A Preferred shares). APFA owns or holds interest 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 directly owns a 99.9% interest the New Hampshire limited liability company Clement Dam Hydroelectric, LLC ("**Clement LLC**") which owns the Clement Dam Hydro Facility. APFA also wholly owns Algonquin Power Fund (America) Holdco Inc., a Delaware corporation, which holds the remaining 0.1% interest in Clement LLC. On March 14, 2013, APCo entered into an agreement to sell Clement LLC. The sale, which is subject to certain regulatory approvals and other conditions precedent, is expected to close in 2014.

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 Caribou and Squa Pan diesel facilities. 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 60% equity interest in Wind Portfolio SponsorCo LLC ("**SponsorCo**"), a Delaware LLC; the remaining 40% interest is held by Gamesa Wind US, LLC (successor to Gamesa Energy USA, LLC), an independent party unrelated to APUC. 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 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 1) Inc. both of which are Delaware corporations.

(ii) **Utilities Business**

Liberty Utilities 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 System**").

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. ("**Peach State**"), a Georgia corporation. 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 Services Corp., a Kansas corporation, which in turn owns Liberty Services (Massachusetts) Corp., 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. (the "**Pine Bluff Water System**"), which owns and operates the Pine Bluff Water System located in Pine Bluff, Arkansas. These assets were acquired on February 1, 2013.

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, Liberty SubCo is the parent company of the water and wastewater entities.

Liberty SubCo owns, through subsidiaries, the water and wastewater businesses located in Arizona, Texas, Missouri and Illinois. All of these 100% wholly-owned subsidiaries (except Liberty Utilities (Northwest Sewer) Corp. (the "**Northwest Waste System**") 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. The Northwest Waste System, an Arizona corporation, has provided an undertaking to a group of developers and homeowner's associations located to the west of Phoenix to apply for a Certificate of Convenience and Necessity and, if successful, to operate a wastewater treatment utility in those areas.

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) Other

Outside of APCo, LU Canada and their respective subsidiary entities, as described above, APUC beneficially owns, directly or indirectly 100% of the following entities: 3793257 Canada Inc. ("**3793257**"), a holding company incorporated under the CBCA; and Windlectric Inc. ("**Windlectric**"), a federal corporation that is developing various wind projects including one in Saskatchewan and one in Ontario.

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 directly and indirectly owns 99.99% of Davis Road LP, an Ontario limited partnership, and it also owns 100% of Davis Road GP Inc., the general partner of Davis Road LP.

(b) 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 and Tranche B term loan interests 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 loans bear interest at the rates of 10.789% and 4.91%, respectively.

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

(a) 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 $0.085 per share or $0.34 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 conducts its business primarily through two separate subsidiaries: APCo which owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation utility assets; and Liberty Utilities, a diversified rate regulated utility which owns and operates a portfolio of North American electric, natural gas and water distribution and wastewater collection utility systems.

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

APCo owns or has interests in hydroelectric generating facilities with a combined generating capacity of approximately 125 MW. APCo also owns or has interests in wind powered generating facilities with a combined generating capacity of 650 MW. Approximately 82% of the electrical output from the hydroelectric and wind generating facilities is sold pursuant to long term contractual arrangements which have a weighted average remaining contract life of 14 years.

APCo owns or has interests in thermal energy generating facilities with approximately 350 MW of installed generating capacity. Approximately 93% of the electrical output from the owned thermal generating facilities is sold pursuant to long term power purchase agreements ("PPA") with major utilities and which have a weighted average remaining contract life of 6 years.

APCo also has a pipeline of development projects that between 2014 and 2016 will add approximately 323 MW of generation capacity from wind powered generating stations and approximately 30 MW from photovoltaic solar powered generation 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.

Utilities: Liberty Utilities is a diversified rate regulated utility providing electricity, natural gas, water distribution and wastewater collection utility services to approximately 480,800 connections. Liberty Utilities 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, Liberty Utilities delivers continued growth in earnings through accretive acquisition of additional utility systems.

The utility systems owned by Liberty Utilities operate under rate regulation, generally overseen by the public utility commissions of the states in which they operate. Liberty Utilities serves approximately 97,400 regulated water distribution and wastewater collection connections, 91,600 electric connections and 291,800 natural gas connections.

Liberty Utilities reports the performance of its utility operations through three regions – West, Central, and East:

The Liberty Utilities (West) region is comprised of regulated electrical and water distribution and wastewater collection utility systems and serves approximately 115,800 connections in the states of Arizona and California.

The Liberty Utilities (Central) region is comprised of regulated natural gas and water distribution and wastewater collection utility systems and serves approximately 115,000 connections located in the states of Arkansas, Illinois, Iowa, Missouri, and Texas.

The Liberty Utilities (East) region is comprised of regulated natural gas and electric distribution utility systems and serves approximately 250,000 connections located in the states of Georgia, Massachusetts, and New Hampshire.

Detailed information on the water distribution and wastewater, electrical distribution, and natural gas distribution utilities owned and operated by Liberty Utilities are set out in Schedule C, D, and E, respectively.

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.

(a) **Fiscal 2011**

Corporate

(i) **Issuance of $95.3 million of Common Shares**

On October 27, 2011, APUC completed a public offering ("**Offering**") of 15,100,000 common shares at a price of $5.65 per share, for gross proceeds of approximately $85.3 million. On November 14, 2011, the underwriters exercised a portion of the over-allotment option granted with the Offering and an additional 1,769,000 common shares were issued on the same terms and conditions of the Offering. As a result, APUC issued an aggregate of 16,869,000 common shares under the Offering for the total gross proceeds of approximately $95.3 million.

The net proceeds of the Offering were used to fund growth initiatives for both Liberty Utilities and APCo, to partially repay existing indebtedness and for other general corporate purposes.

(ii) **Conversion of Convertible Debentures to Equity**

Effective May 16, 2011 ("**Series 1A Redemption Date**"), APUC redeemed $2.1 million, being all of the remaining issued and outstanding principal amount, of Series 1A 7.5% convertible unsecured subordinated debentures due November 30, 2014 ("**Series 1A Debentures**") and issued 430,666 Common Shares upon the redemption. Between January 1, 2011 and the Series 1A Redemption Date, $60.3 million principal amount of Series 1A Debentures were converted by debenture holders into 14,788,976 Common Shares.

(iii) **Strategic Investment Agreement with Emera**

On April 29, 2011, APUC entered into a strategic investment agreement (the "**Strategic Investment Agreement**") with Emera Incorporated ("Emera") which establishes how APUC and Emera will work together to pursue specific strategic investments of mutual benefit. The Strategic Investment Agreement builds on the strategic partnership effectively established between the two companies in April 2009.

The Strategic Investment Agreement outlines "areas of pursuit" for each of APUC and Emera. For APUC, these include investment opportunities relating to unregulated renewable generation, small electric utilities and gas distribution utilities. For Emera, these include investment opportunities related to regulated renewable generation and transmission projects within its service territories and large electric utilities. APUC is committed to working with Emera on opportunities that fit within APUC's "areas of pursuit".

As an element of the Strategic Investment Agreement, Emera is able to acquire up to 25% of APUC through the purchase of Common Shares issued by APUC to fund certain investment opportunities under the Strategic Investment Agreement. The Strategic Investment Agreement was approved by shareholders at the annual and special meeting held on June 21, 2011.

APUC share purchases are generally made by Emera through the acquisition of subscription receipts in exchange for promissory notes at an agreed upon price, which are then exchangeable into Common Shares upon meeting certain transaction specific conditions, or at a later date at Emera's option, as applicable.

Liberty Utilities

(i) **CalPeco Electric System**

On April 29, 2011, pursuant to the Strategic Investment Agreement, Emera and APUC agreed to the general terms by which Emera would sell its 49.999% direct ownership in the CalPeco Electric System to APUC, with closing of such transaction subject to, among other things, execution of a definitive purchase agreement and regulatory approval. On September 12, 2011, Emera US Holdings Inc., a subsidiary of Emera through which it holds its interest in the CalPeco Electric System, entered into a definitive purchase agreement with Liberty Utilities. In connection with this transaction, Emera entered into a subscription agreement with APUC dated September 12, 2011, pursuant to which Emera subscribed for an aggregate of 8,211,000 subscription receipts from APUC at a price of $4.72 per subscription receipt. Payment for these subscription receipts was satisfied by delivery by Emera of two non-interest bearing promissory notes, one in the amount of $22,608,800 and one in the amount of $16,147,120. The transaction was completed in 2012.

APCo - Power Generation

(i) **AES Standard Offer Contract**

In 2011, AES entered into a three year contract with Maine Public Service Company ("**MPS**"), a regulated electric transmission and distribution utility serving approximately 36,000 electricity customer accounts in Northern Maine, starting March 1, 2011 to provide standard offer service to multiple commercial and industrial customers in Northern Maine. The anticipated customer load associated with the standard offer service is approximately 135,000 MW-hrs.

(ii) **Windsor Locks Thermal Facility Repowering**

The Windsor Locks Thermal Facility is a 56 MW natural gas powered electrical and steam energy generating facility located in Windsor Locks, Connecticut. This facility delivers 100% of its steam capacity and a portion of its electrical generating capacity to Ahlstrom pursuant to an energy services agreement ("**ESA**").

APCo entered into an agreement to extend the ESA with Ahlstrom from 2017 to 2027, and initiated the process to acquire a new combustion gas turbine which would be more appropriately sized to meet the electrical and steam requirements of the steam host. The new turbine was placed in operation in 2012.

(iii) **Red Lily Wind Facility**

On February 28, 2011, the Red Lily Wind Facility commenced commercial operation under its PPA. APUC's investment in the Red Lily Wind Facility had been initially structured in the form of senior and subordinated debt investment of approximately $19.6 million with returns to APUC from the project coming in the form of interest payments and other fees in 2011. APUC has the option to formally exchange its debt investment for a 75% equity position in the facility in 2016.

(iv) **APCo Senior Unsecured Debentures**

On July 25, 2011, APCo issued $135 million in senior unsecured debentures (the "**2011 APCo Debentures**") by way of private placement. The net proceeds from the 2011 APCo Debentures were used to repay the outstanding senior project debt financing related to the St. Leon Wind Facility (the "**AirSource Senior Debt**") and to reduce amounts outstanding under APCo's senior revolving credit facility. The 2011 APCo Debentures mature on July 25, 2018, and bear interest at a rate of 5.50% per annum, calculated semi-annually payable on January 25 and July 25 each year, commencing on January 25, 2012.

(v) **APCo Credit Facility Renewal**

On January 14, 2011, APCo received commitments from a syndicate of Canadian banks for a new $142 million credit facility with a three year term (the "**APCo Credit Facility**"). APCo reduced the amount of the APCo Credit Facility to $120 million following the completion of the 2011 APCo Debentures private placement in July 2011.

(b) **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 in connection with certain previously announced and completed transactions. The shares were issued in the context of the existing Strategic Investment Agreement 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 $0.9 million of principal amount of Series 3 Debentures outstanding.

(vi) **APUC Credit Facility**

On November 19, 2012, APUC entered into an agreement for a $30.0 million senior unsecured revolving credit facility (the "**APUC 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.

Liberty Utilities

(ii) **Acquisition of Remaining Interest in CalPeco Electric System**

On December 21, 2012, Liberty Utilities 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. Liberty Utilities 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.

(iii) **Acquisition of New Hampshire Utility**

On July 3, 2012, Liberty Utilities 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.

(iv) **Acquisition of Midstates Gas System**

On August 1, 2012, Liberty Utilities completed the acquisition of regulated natural gas distribution utility systems located in Missouri, Illinois, and Iowa from 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.

(v) **U.S. Debt Private Placements**

In connection with the above noted gas and electric utility acquisitions during the third quarter of 2012, Liberty Utilities 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.

(vi) **Expansion of Liberty Credit Facility**

In 2012, Liberty Utilities entered into an agreement for a U.S. $100 million senior unsecured revolving credit facility (‘**Liberty Credit Facility**”) with a consortium of U.S. banks. The Liberty Credit Facility is used for general corporate purposes and has a three year term with a maturity date of January 18, 2015.

APCo - Power Generation

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

In 2012 APCo completed its 60% equity investment in the U.S. Wind Portfolio Facilities for consideration of $271.7 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 renewable energy credits, are sold into the energy markets in which the facilities are located.

(ii) **APCo $150 million Senior Unsecured Debentures**

On December 3, 2012, APCo issued $150 million 4.82% senior unsecured debentures with a maturity date of February 15, 2021 (the "**2012 APCo Debentures**") pursuant to a private placement in Canada and the United States. The 2012 APCo 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, APCo entered into a fixed cross currency swap, coterminous with the 2012 APCo 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 APCo Debentures were used primarily to fund the investment in the U.S. Wind Portfolio.

(iii) **APCo Credit Facility**

On November 16, 2012, APCo amended the APCo 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 APCo Credit Facility is now fully unsecured.

(iv) **Completion of Windsor Locks Thermal Facility Repowering**

APCo 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, APCo 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.

(C) Fiscal 2013

Corporate

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

APUC has completed several acquisitions and has advanced a number of other initiatives 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 May 9, 2013, the Board approved a dividend increase of $0.03 per share annually bringing the total annual dividend to $0.34, paid quarterly at the rate of $0.085 per Common Share.

Management believes that the increase in the 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.

(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.

According to S&P, the upgrade reflects a significant increase in regulated cash flow from Liberty Utilities owing to a number of acquisitions in the past 18 months, as well as an expectation that adjusted funds from operations-to-debt levels will continue to increase in the near-to-medium term. S&P has also 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.

The Corporation expects the rating to further improve access to the debt capital markets, reduce credit charges and results in a lower overall cost of capital.

(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 initiated in 2011 has now been completed and all related party transactions between APUC and the CEO and Vice Chair have been resolved 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 2.6 million Common Shares at a price of $5.74 per share to Emera. Additionally, on February 14, 2013, APUC issued 5.2 million 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.

As a result, as at December 31, 2013, Emera owns 50.1 million Common Shares representing approximately 24.2% of the total outstanding Common Shares.

(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 APUC Credit Facility**

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

Liberty Utilities

(i) **Acquisition of the New England Gas System**

On February 11, 2013, Liberty Utilities 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. The results of the New England Gas System are reported in the Liberty Utilities (East) region.

Total purchase price for the New England Gas System was approximately U.S. $59.1 million, subject to certain working capital and other closing adjustments. 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, Liberty Utilities 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 Liberty Utilities 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, Liberty Utilities 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) **Acquisition of Remaining Interest in the CalPeco Electric System**

On February 14, 2013, APUC issued 3.4 million common shares to Emera representing the balance of the subscription receipts outstanding pursuant to the acquisition in 2012 of the remaining 49.999% ownership in California Pacific Utility Ventures LLC, which indirectly owned 100% of the CalPeco Electric System.

(v) **U.S. Debt Private Placements**

On July 31, 2013, Liberty Utilities 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 Liberty Credit Facility and for general corporate purposes.

On March 14, 2013, Liberty Utilities 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%.

(vi) **Expansion of the Liberty Credit Facility**

On September 30, 2013, Liberty Utilities increased the credit available under the Liberty Credit Facility to U.S. $200.0 million from U.S. $100.0 million. The larger credit facility provides Liberty Utilities 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.

(vii) **Granite State Electric System Rate Proceedings**

On March 29, 2013, the Granite State Electric System filed a rate case with the 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. The filing is based on a 2012 test year, with revenues and expenses adjusted to reflect known and measurable changes. Among other things, Granite State Electric System requested and received approval to continue the current cost-recovery tracking mechanism related to the Reliability Enhancement and Vegetation Management Plan and was granted an annual rate increase of U.S. $0.4 million starting July 1, 2013. The Granite State Electric System also requested a modification to allow for recovery of pre-staging personnel and equipment for qualifying storms. On June 27, 2013, the NHPUC approved a settlement agreement authorizing a temporary annual rate increase of U.S. $6.5 million effective July 1, 2013, and provides recognition for the Granite State Electric System to request an increase to its storm recovery adjustment factor ("SRAF"). On January 22, 2014, the Granite State Electric System entered a settlement with the NHPUC Staff, which will provide for a rate increase of U.S. $10.9 million, consisting of U.S. $9.8 million in base rates and an additional U.S. $1.1 million for incremental capital expended after the test year. In addition, the settlement allows for one time recovery of rate case expenses of U.S. $0.4 million. It is anticipated that the settlement will be approved late in Q1 2014.

APCo - Power Generation

(i) **Agreement to acquire the remaining 40% of the US Wind Portfolio Facilities**

On November 28, 2013, APCo entered into an agreement to acquire the remaining 40% of the 400 MW U.S. Wind Portfolio Facilities from Gamesa USA for total consideration of approximately U.S. $117.0 million.

Since APCo has been the majority owner and manager of the U.S. Wind Portfolio Facilities since 2012 when commercial operation was achieved, no additional ongoing management or administrative costs are expected to be incurred. Gamesa USA will continue to provide operations, warranty and maintenance services for the wind turbines and balance of plant facilities under 20 year contracts. The acquisition will be funded primarily from the proceeds from the $200.0 million of APCo debentures issued early in 2014.

(ii) **Acquisition of the 20 MWac Bakersfield Solar Project**

On November 28, 2013, APCo 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. APCo plans to enter 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. It is anticipated that the total expected capital costs for the project of U.S. $58.5 million will be funded as to 55% by APCo and the balance by the Tax Partner. Subject to receipt of final permits and approvals and reaching satisfactory agreement with the Tax Partner, construction of the project is anticipated to commence in the second quarter of 2014 with a commercial operations date expected to occur in late 2014.

(iii) **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 and 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.

(iv) **Energy From Waste Facility**

During the second quarter of 2013, APCo concluded that its EFW 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, APCo entered into an agreement to sell the EFW and BCI Thermal Facilities. 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 final selling price is subject to customary closing adjustments. Closing of the transaction is subject to certain regulatory approvals which are expected to be received in the first half of 2014. The operating results from these facilities for current and prior periods are therefore disclosed as discontinued operations on the consolidated statements of operations.

(v) **Completion of Cornwall Solar Project**

During the second quarter of 2012, APCo began construction of the 10 MWac solar project located near Cornwall, Ontario. The facility is the first solar project in APCo's portfolio and is expected to add 13,900 MW-hrs of production annually. Completion of construction is expected late in the first quarter of 2014 at an estimated total capital cost of $45.0 million.

(vi) **Sale of Small U.S. Hydro Facilities**

On March 14, 2013, APCo 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. APCo closed the sale of nine of the ten facilities on June 28, 2013 for total proceeds of approximately U.S. $23.4 million with the sale of the tenth facility expected to close in the second quarter of 2014. The operating results from these facilities for current and prior periods are therefore disclosed as discontinued operations on the consolidated statements of operations.

2.3 Recent Developments - 2014

Corporate

(i) Issuance of $100 million of Preferred Shares

Subsequent to year-end, 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 million. The Series D Shares will yield 5.0% annually for the initial five-year period ending March 31, 2019. The Series D 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.

APCo – Power Generation

(i) **APCo $200 million Senior Unsecured Debentures**

On January 17, 2014, APCo issued $200.0 million 4.65% senior unsecured debentures with a maturity date of February 15, 2022 ("**2014 APCo Debentures**") pursuant to a private placement. The 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, APCo entered into a fixed for fixed cross currency swap, coterminous with the 2014 APCo 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 will be used towards financing the acquisition of the remaining 40% ownership interest in its U.S. Wind Portfolio Facilities, to reduce amounts outstanding on project debt related to its Shady Oaks Wind Facility, to reduce amounts outstanding under the APUC Credit Facility and for general corporate purposes.

3. DESCRIPTION OF THE BUSINESS

3.1 General Description of the Regulatory Regimes in which the Business Operates.

(a) Power Generation Regulatory Regimes

(i) Canada

The majority of the electricity supplied within the Canadian provinces is generated by Crown corporations, such as Ontario Power Generation Inc. and Hydro-Québec, or investor-owned utilities, such as APUC. 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 APCo 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 APCo 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 in connection with the operation of APCo's business.

(ii) United States

The power generation industry in the United States is regulated by the United States Federal Energy Regulatory Commission ("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").

a. Rate Regulation

All of APUC's U.S. power generation facilities either have market based rate authority ("MBR Authority") or are Qualifying Facilities ("QFs") that sell power under the PURPA regulatory structure, both of which are less onerous than traditional cost-of-service rate regulation. FERC grants MBR Authority to applicants that can demonstrate that they do not have or have adequately mitigated horizontal and vertical market power in the relevant markets. MBR Authority allows facilities to sell into the market at the prevailing rate. QFs that qualify to sell power under PURPA are exempt from sections 205 and 206 of the FPA and sell power at the Avoided Cost.

b. PUHCA

APUC is also subject to the PUHCA. PUHCA imposes certain books and records requirements on public utility holding companies. Although APUC is subject to PUHCA's requirements, APCo qualifies for an exemption from PUHCA under Section 366.3 of the regulations of the FERC. Section 366.3 provides that holding companies that are subject to PUHCA solely by virtue of ownership of QFs, exempt wholesale generators ("EWGs") and foreign utility companies ("FUCOs") are exempt from PUHCA's requirements. Should any of APCo's subsidiaries cease to be a QF, EWG, or FUCO, APCo will also be subject to PUHCA's books and records requirements.

(b) **Water Utility Services Regulatory Regimes**

Investor-owned utilities are 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%.

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.

(c) **Electrical Utility Services Regulatory Regimes**

The electricity industry remains perhaps the most 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.

Investor-owned electricity utilities are 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, services, 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 reliable service and adequate supplies of electricity together with financial security, transparency in the rate setting process and reasonable prices.

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 services company the opportunity, but not the guarantee, to earn a reasonable return on its investment after recovering its prudently incurred operating expenses.

(d) **Natural Gas Utility Services Regulatory Regimes**

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.

Investor-owned natural gas utilities are 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, services, 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 reliable service and adequate supplies of natural gas together with financial security, transparency in the rate setting process and reasonable prices.

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 Production Method, Principal Markets, Distribution Methods and Material Facilities

(a) **Power Generation: Renewable - Hydroelectric**

(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 markets are Maine, New York State and New Hampshire. 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 APCo'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. 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 has 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) (the "Electricity Act"), 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

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 five years, APUC has spent approximately $2.2 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 $15.4 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:

	Total (millions)	2014	2015	2016	2017
Estimated future Bill C-93 Capital Expenditures	**15.4**	1.0	7.3	6.8	0.3

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

- APCo completed the majority of the second phase of the on-site remediation work for the Mont Laurier Hydro Facility in 2013 at a capital cost of approximately $0.2 million. The on-site remediation is now substantially complete.

* In 2013 APCo completed a risk review of the of the dam rehabilitation plan for the Donnacona Hydro Facility and will explore methods to reduce risk associated with the rehabilitation project in 2014. The remedial on-site work is anticipated to start in 2015 and be completed in 2016.

* The dam safety study and a detailed condition assessment for the St. Alban Hydro Facility have been completed. A small portion of the on-site remediation associated with the spillway gate superstructure was performed in 2013 at a cost of $0.1 million. APCo anticipates engineering and regulatory review for the remediation of the main dam to be performed in 2014, with remedial work in 2015 to 2016.

* APCo is presently reviewing options with respect to the Belleterre Hydro Facility including the removal of several small dams that are not required for power generation. APCo anticipates completion of any required work on these dams by 2017.

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

* The dam remediation work related to the Rawdon and Chute Ford Hydro Facilities has been completed.

In addition to the C-93 related dam remediation work, APCo 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 APFC. 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 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, 65% of any incremental after tax cash flows from 2014 to 2027 and 58% 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 index (a minimum of 1% to a maximum of 8%).

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 $37.4 million as at September 30, 2013.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. At December 31, 2013, the debt reserve was fully funded using the irrevocable letter of credit.

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, 65% from 2014 to 2027 and 58% 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 APFC 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. Unit 5 of the facility is currently operating as a fixed-bladed runner. Historical gross generation from the station averages 140,000 MW-hrs per year. The Tinker Hydro Facility benefits from the flow regulation of the Caribou 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 AES for resale to commercial and industrial customers in the northern Maine and New Brunswick markets, as well as energy and capacity to the Maine and New Brunswick electricity markets.

(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.

(b) **Power Generation: Renewable - Wind Power**

(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 Facility and St. Leon II Wind Facility, and Saskatchewan for the Red Lily 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 in the case of the St. Leon Wind Facility and St. Leon II Wind Facility, and Saskatchewan Power Corporation in the case of the Red Lily I 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.

(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) 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.

(4) 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. APUC anticipates that the St. Leon Wind Facility will earn WPPI of approximately $3.0 million annually based on the current estimated long term wind resource.

(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. Construction of the St. Leon II Wind Facility was completed in the first quarter of 2012 for a total capital cost of $29.3 million. Beginning July 1, 2012, the facility was generating revenues in accordance with its PPA.

In July 2011, an affiliate of APCo 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.

St. Leon II LP and St. Leon II Wind Energy GP Inc. have entered into an Amended and Restated PPA with Manitoba Hydro dated as of April 4, 2012 under which all electricity produced at the St. Leon II Wind Facility is sold to Manitoba Hydro. The term of the PPA is 25 years, with a renewal term of up to an additional two years, on a season by season basis, at the St. Leon II LP's option. Under the terms of the PPA, operational security in the amount of approximately $300,000 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.

(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. Additional senior debt of $31 million has been provided by a third party lender, Integrated Private Debt. As at December 31, 2013, APUC had 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 interest at the rate of 12.5% per annum. 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) 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 renewable energy credits 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, 2013, the outstanding amount of the Shady Oaks Project Wind Facility project debt facility with the China Development Bank Corporation was U.S. $122.0 million. On APUC's year end financial statements for the twelve months ended December 31, 2013, 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, 2014, and November 15, 2014. The semi-annual principal repayment schedule under the facility for the following 12.5 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 facility may be repaid in whole or in part at any time without penalty and bears interest at LIBOR plus 280 basis points.

Subsequent to December 31, 2013, U.S. $40.0 million was repaid on such facility.

(5) 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 60% of the managing ownership interests in Sandy Ridge Wind, LLC through SponsorCo, and has entered into an agreement to acquire the remaining 40% interest in SponsorCo, which is expected to close in early 2014.

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 the Primary Energy Production Hedge. Beginning January 1, 2014, all energy produced in excess of that included in the Primary Energy Production Hedge is sold under a short term energy production hedge ("Secondary Energy Production Hedge") between AES and a North American energy company. The life of the Secondary Energy Production Hedge commitment is limited to the calendar year 2014. Ancillary services, including capacity and renewable energy credits, are sold into the energy market in which the Sandy Ridge Wind Facility is registered.

(6) 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 60% of the managing ownership interests in Minonk Wind, LLC through SponsorCo, and has entered into an agreement to acquire the remaining 40% interest in SponsorCo, which is expected to close in early 2014.

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 the Primary Energy Production Hedge. Beginning January 1, 2014, all energy produced in calendar year 2014 excess of that included in the Primary Energy Production Hedge is sold under a Secondary Energy Production Hedge. Ancillary services, including capacity and renewable energy credits, are sold into the energy market in which the Minonk Wind Facility is registered.

(7) 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 60% of the managing ownership interests in Senate Wind, LLC through SponsorCo, and has entered into an agreement to acquire the remaining 40% interest in SponsorCo, which is expected to close in early 2014 following regulatory approval.

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 the Primary Energy Production Hedge. Beginning January 1, 2014, all energy produced in the calendar year 2014 in excess of that included in the Primary Energy Production Hedge is sold under a Secondary Energy Production Hedge. Renewable energy credits are sold into the energy market in which the Senate Wind Facility is eligible to sell such products.

(c) **Power Generation: Thermal - Energy From Waste**

(i) **Production Method**

In North America and elsewhere, the combination of increasing population and stricter environmental regulations has imposed increasing limitations upon the development of new municipal landfills and on the expansion of existing landfills. Energy-from-waste facilities are considered a viable option to reduce the total tonnage of municipal waste being directed to landfills and to extend the useful life of existing landfills. The establishment of energy-from-waste facilities is now a licensed process in certain states of the United States and Canadian provinces.

The incineration process reduces the waste to an ash which is less than one third of the original volume of waste. The residual ash is then transported to a landfill. The heat recovered from municipal solid waste is used to make steam which can be used to provide thermal energy or can be used to drive turbines and generate electricity.

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

See the section entitled "*Material Facilities*" immediately below.

(iii) **Material Facilities**

(1) EFW Facility

The EFW Facility is a 10 MW generating facility located in Brampton, Ontario which produces electricity from incinerating non-recyclable materials, including municipal solid waste. The facility is designed to incinerate over 500 tons per day of municipal solid waste from five incinerators to produce an average of approximately 60,000 pounds per hour of steam which is the excess of the steam required for production of internally consumed electricity.

In 2012, the EFW Facility received approval from the Ontario Ministry of Environment for an amendment to its environmental permits allowing the EFW Facility to accept municipal, industrial, commercial and institutional waste from anywhere in Ontario. In addition the facility is permitted to accept international airport waste from Pearson and Hamilton International Airports. In October 2012, the EFW Facility's contract with Peel concluded. APUC has now entered into several waste supply agreements with both municipal and commercial entities to ensure continued operation of the facility. In addition, APUC has entered into several agreements to market the EFW Facility capacity in various commercial waste sectors, including specialty wastes and products.

The majority of the EFW Facility steam is diverted to the BCI Thermal Facility. See "*Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Thermal: Cogeneration – Material Facilities – BCI Thermal Facility*". A portion of the EFW Facility

steam is used by the EFW Facility to generate electricity in a steam turbine generator, the electricity from which is used to supply internal operations, with any excess generation being sold to OEFC.

During the second quarter of 2013, the Company concluded that its EFW 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 its estimated fair value, less cost of sale which resulted in a write down of $35.7 million, net of tax. On February 7, 2014 the Company entered into an agreement to sell the EFW Facility and BCI Thermal Facility. Accordingly, the determination of the fair values of the net assets of EFW Facility and BCI Thermal Facility 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 final selling price is subject to customary closing adjustments. Closing of the transaction is subject to certain regulatory approvals which are expected to be received by the end of the first quarter or early in the second quarter of 2014.

The EFW Facility is selling electricity at the Hourly Ontario Energy Price. The Hourly Ontario Energy Price is the hourly price that is charged to local distribution companies, other non-dispatchable loads and self-scheduling generators.

(d) **Power Generation: Thermal - Cogeneration**

(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, electrical capacity and other ancillary services are sold either under the terms

of a long term contract or according to the Independent System Operator rules. In addition to grid sales of electricity and power, electricity and thermal energy is also sold to nearby third party purchasers for use in their production facilities.

(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 natural gas fired turbine, commissioned in 2008, and a 12.5 MW Westinghouse steam turbine, originally commissioned in 1991. In 2012, APUC successfully completed a major outage 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 dated August 1, 2006 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 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.

There is an outstanding senior loan against the Sanger Thermal Facility in the amount of U.S. $19.2 million as at December 31, 2013. The loan is a California Pollution Control Finance Authority Variable Rate Demand Resource Recovery Revenue Bond, due September 15, 2020. The senior loan bears interest at variable rates, reset monthly. Interest is payable monthly with no principal repayments. The effective interest rate in 2013 was 1.72%. The loan is secured solely by the facility, the ownership interests therein and an irrevocable letter of credit in an amount of U.S. $19.5 million.

(2) Windsor Locks Thermal Facility

APUC has completed the repowering of the Windsor Locks thermal facility's (the "**Windsor Locks Thermal Facility**") electrical and steam energy generating station. The installation of a new 15 MW Solar Titan combustion gas turbine was completed in July 2012 at a total capital cost of U.S. $18.3 million (net one-time non-recurring grants from the state of Connecticut and the US federal government.) and is now fully operational. As part of the repowering project APUC also entered into an extension of the energy services agreement with Ahlstrom Windsor Locks, LLC 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 now available as a peaking turbine to generate additional revenues.

With the repowering complete 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 the ESA. Pursuant to the ESA, Ahlstrom leases the facility site to Windsor 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. APUC's AES group manages the off-take sales from the Windsor Locks Thermal Facility into the ISO-NE market.

Natural gas for the Windsor Locks Thermal Facility is delivered to the facility by Colonial Energy, Inc. a retail natural gas marketer that holds capacity on Yankee Gas Service Company's distribution system. 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.

(3) BCI Thermal Facility

The BCI Thermal Facility is a cogeneration facility located in Brampton, Ontario on the EFW Facility site. It was commissioned and became operational in June 2008. The project was established to meet the steam requirements of a nearby recycled paper board manufacturing mill that requires approximately 90,000 pounds of steam per hour in its manufacturing activities.

The BCI Thermal Facility consists of a 150,000 pound per hour gas-fired boiler, a water treatment system, pumps to support the boiler, a twelve inch diameter pipeline to supply a nearby recycled paper board manufacturing mill with steam and a six inch diameter pipeline for condensate return. The majority of the steam supplied to the mill is produced by the EFW Facility with the gas-fired auxiliary boiler supporting peak steam demand and providing full standby capacity during normal downtime periods at the EFW Facility and where operations at the EFW Facility cannot provide sufficient volume of steam.

During the second quarter of 2013, the Company concluded that its EFW 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 its estimated fair value, less cost of sale which resulted in a write down of $35.7 million, net of tax. On February 7, 2014 the Company entered into an agreement to sell the EFW Facility and BCI Thermal Facility. Accordingly, the determination of the fair values of the net assets of EFW Facility and BCI Thermal Facility 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 final selling price is subject to customary closing adjustments. Closing of the transaction is subject to certain regulatory approvals which are expected to be received by the end of the first quarter or early in the second quarter of 2014.

(4) Kirkland Thermal Facility

The Kirkland thermal facility ("**Kirkland Thermal Facility**") is a 132MW combined cycle integrated fuels generating facility located in Kirkland Lake, Ontario owned by Kirkland Lake Power Corp. (“Kirkland”) which burns natural gas and wood waste to generate electricity using four gas turbines and two steam turbines. The Kirkland Thermal Facility was developed in two phases: the first 102MW was commissioned in 1991, operating in baseload, and the remaining 30MW was added in 2004 as a dispatchable or peaking plant. Northland Power Inc. (“Northland”) manages the operations. Electricity produced by the Kirkland Thermal Facility is sold to OEFC pursuant to a 40 year contract, which expires in 2030. Natural gas used by the Kirkland Thermal Facility is supplied under 20 year supply contracts. Price increases under such gas supply agreements are generally tied to price increases under the PPAs with OEFC. Wood waste consumed by the facility is supplied by local forest product companies under contracts of varying terms with the longest being 25 years.

APT owns 32.4% of the Class B non-voting shares issued by Kirkland. It is Kirkland’s policy to declare and pay quarterly dividends on its shares equal to substantially all of its after-tax income. Kirkland had a put option to sell the Kirkland Thermal Facility to Northland with an exercise date of February 28, 2011 at an exercise price of $10 million. Further to a shareholder meeting on November 12, 2009, the Kirkland shareholders decided not to exercise the put option as the present value of the expected future dividends from this investment were expected to exceed funds they would receive from the put option. As a result, subsequent to February 28, 2011, 75% of operating

income of the Kirkland facility is paid to Northland under the management agreement, whereas 32.4% of the remaining 25% of after tax income is then paid to APT.

(5) Cochrane Thermal Facility

The Cochrane thermal facility ("**Cochrane Thermal Facility**") is a 40MW combined cycle integrated fuels generating facility located in the Town of Cochrane, Ontario. The Cochrane Thermal Facility is owned by Cochrane Power Corporation ("Cochrane") which burns natural gas and wood waste to generate power using a gas turbine and a steam turbine. The Cochrane Thermal Facility was commissioned in 1990 and is currently managed by Northland. Electricity produced by the Cochrane Thermal Facility is sold to OEFC pursuant to a 25 year contract, which expires in 2014. The majority of the natural gas used by the Cochrane Thermal Facility is supplied under a supply contract which expires in 2016. Price increases under such gas supply agreements are generally tied to price increases under the PPA with OEFC. Wood waste consumed by the Cochrane Thermal Facility is supplied by local forest product companies under contracts of varying terms with the longest being 25 years.

APT owns 25% of the Class B non-voting shares issued by Cochrane. It is Cochrane's policy to declare and pay quarterly dividends on its shares equal to substantially all of its after-tax income. Currently, 75% of operating income of the facility is paid to Northland under the management agreement and the remaining 25% of after-tax income is paid to APT.

(e) **Power Generation: Algonquin Energy Services**

The primary business of AES is to market the output of the Tinker Hydro Facility and other owned assets of APUC which would otherwise sell the energy they generate on a merchant basis. AES also works to develop strategies for selling the power output of other facilities of APUC that are approaching the end of their PPAs and to engage, where possible, in actual selling of power for APUC's facilities that would otherwise sell power on a merchant basis.

AES provides standard offer contracts and direct customer contracts for the supply of energy to commercial and industrial customers using a series of short-term energy supply agreements.

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

AES provides energy to commercial and industrial customers in the Maine and New Brunswick markets. AES purchases energy from the Tinker Hydro Facility. Based on historical long term average levels of hydroelectric energy generation, the Tinker Hydro Facility is anticipated to provide greater than 65% of the energy required by AES to service its customers and provides a natural hedge on supply costs of AES.

AES purchases additional energy on the open market to supplement the purchases from the Tinker Hydro Facility in order to service its customer demand. AES manages the risk associated with this business through the purchase of fixed volume/prices from the market. In addition, AES negotiates appropriate consumption volumes and pricing indexes with large retail and wholesale consumers in northern Maine to ensure risk associated with volatility of consumption by the consumer is mitigated.

AES is responsible for the strategic management of market exposure for the U.S Wind Portfolio and the Shady Oaks Wind Facilities. These wind facilities, located in the PJM and ERCOT markets,

are accompanied by long term hedge or power supply contracts for a large portion of the projected production; AES develops the strategies for managing the production volumes in excess of the volumes sold under the hedge or power supply contracts.

AES is responsible for the execution of the strategic tiered design to sell current and 3 to 5 year forward Renewable Energy Certificate (REC) products from the Corporation's various qualified generators in ERCOT, PJM and ISO-NE markets as well as fulfilling the required purchase obligations for the Corporation's retail load in Maine. AES is responsible for the contracting, tracking and delivery of these RECs to/from each counterparty.

(f) **APCo: Development Division**

(i) **Target Markets / Development 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.

The Development Division may also create opportunities through the acquisition of operating assets with accretive characteristics and prospective projects that are at various stages of development. The Development Division believes that the prevailing economic climate has also created opportunities for APCo to acquire third party development projects on terms that require the experience and financial resources that APCo 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.

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 APUC will begin construction.

(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 Ontario government has reviewed and continues to support the Feed-in-Tariff (“**FIT**”) program originally passed under the Green Energy Act, 2009. Accordingly the OPA continues to offer standard pricing for electricity from renewable sources. In addition the OPA has announced that in 2014 it intends to issue a Request For Proposals 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 early 2015. Nova Scotia also continues to offer its community feed-in-tariff program, albeit on a smaller

scale. In July of 2012, Quebec announced the intention to procure up to 700 MW of wind generation through a request for proposals, Saskatchewan recently announced the intention to procure additional renewable energy generation and British Columbia continues to offer its standard offer program for renewable energy projects under 15 MW.

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. Originally enacted in 1992, the PTC has been renewed and expanded numerous times, most recently by the American Recovery and Reinvestment Plan of 2009. Under current legislation, construction of a renewable power facility must have been commenced by December 31, 2013 for the facility to be eligible for PTCs. However additional incentives continue to be offered independently for the development of renewable sources of power at the state and local levels.

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

(iii) **Current Development Projects**

APUC's Development Division has successfully advanced a number of projects and has been awarded or acquired a number of PPAs. The projects are as follows:

Project Name	Location	Size (MW)	Estimated Capital Cost	Commercial Operation	PPA Term	Production GW-hrs
Chaplin Wind[1]	Saskatchewan	177	$ 340.0	2016	25	720.0
Amherst Island[2]	Ontario	75	$ 230.0	2015	20	247.0
Val Eo - Phase I[1,6,7]	Quebec	24	$ 70.0	2015	20	66.0
Morse Wind[3,4]	Saskatchewan	23	$ 81.3	2015	20	108.0
Bakersfield Solar[1,8]	California	20	$ 62.2	2015	20	53.3
St. Damase - Phase I[1,5,7]	Quebec	24	$ 65.0	2014	20	78.7
Cornwall Solar[1,2]	Ontario	10	$ 45.0	2014	20	14.4
Total		353	$ 893.5			1,287.4

1 PPA signed

2 FIT contract awarded

3 Two 10 MW PPAs; one 5MW PPA

4 Comprised of three projects that are connected geographically and will be built simultaneously. All three projects were awarded PPAs under the province's Green Options Partner Program ("GOPP").

5 The St. Damase project is being developed in two phases: Phase I of the project (24MW) will be erected in 2014 and the 101MW 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.

6 The Val Eo project is being developed in two phases: Phase I of the project (24MW) will be erected in 2015 and the 101 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.

7 Size, Estimated Capital Costs, Commercial Operation Date, PPA Term and Production refer solely to Phase I of the St. Damase and Val-Eo wind projects.

8 Total cost the project is expected to be U.S $58.5 million.

(1) Chaplin Wind Project

In the first quarter of 2012, APCo 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 has a targeted commercial operation date of December, 2016. The facility will be constructed at an estimated capital cost of $340 million and consist of approximately 77 multi-megawatt wind turbines. The project is expected to generate first full year 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 favourable location by interconnecting with a nearby 138Kv line and will be compliant with SaskPower's latest interconnection requirements.

The Environmental Impact Assessment was submitted in third quarter of 2013 to the Environmental Assessment Branch, Saskatchewan Environment. Screening was completed, and a proposed layout was requested in order to provide a final determination. A supplemental report was submitted in the fourth quarter of 2013 to address the questions identified during the screening process and the project is awaiting a response from the Environmental Assessment Branch. As a result of continuing development work, the expected capital costs of the project have been reduced to $340 million from the original estimate of $355 million. To optimize the returns associated with the project, APCo intends to enter into a partnership agreement using a similar structure that utilized in the development of the Red Lily Wind Facility.

(2) Amherst Island Wind Project

The Amherst Island wind project is located on Amherst Island near the village of Stella, approximately 15 kilometres 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 efficient Class III wind turbine generator technology. APUC forecasts that the available wind resource could produce approximately 247 GW-hrs of electrical energy annually, depending upon the final turbine selection for the project. Total capital costs for the facility are currently estimated to be $230 million. The financing of the project will be arranged and announced when all required permitting and all other

pre-construction conditions have been satisfied. Environmental studies and engineering are underway.

The Renewable Energy Approval ("REA") application was submitted in April 2013 and was posted to the environmental registry in early January 2014. The REA is now anticipated to be received at the beginning of the third quarter of 2014. Subject to receipt of the REA approval as expected, and dependent on any appeals being launched, construction is expected to commence shortly thereafter; with a planned construction timeframe of 12 to 18 months. Completion is targeted to occur in late 2015 or early 2016.

(3) 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 25MW under Saskatchewan's Green Options Partner Program, SaskPower has offered APUC a 20 year contract for the procurement of 23MW of wind generation to match the name plate capacity of the proposed turbines.

APUC executed an asset purchase agreement with a local developer, to acquire assets related to two adjacent 10 MW wind energy development projects in Saskatchewan and a further 5 MW was developed by APUC 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 total annual energy production for the Morse wind project has increased from 93.0 GW-hrs to 108.0 GW-hrs due to final turbine selection and increased hub height. Accordingly, the capital cost to construct the Morse wind project has also increased and is currently estimated to be $81.3 million, inclusive of acquisition costs. The contract rate is set at $104.02 per MWhr for the first full year of operations, which APCo expects to occur in 2015, with an annual escalation provision of 2% over the expected 20 year term.

The provincial environmental assessment of the site was completed in the first quarter of 2012 and submitted to the provincial Environmental Assessment Branch. In April 2012, the project was deemed a "non-development" by the provincial Environmental Assessment Branch thereby not requiring further environmental assessment review.

(4) Quebec Community Wind Projects

In December 2010, APUC, in partnership with Société en Commandite Val-Éo, a community cooperative with a development project located in the Lac Saint-Jean region of Quebec, and in partnership with the community of Saint-Damase, were awarded PPAs for the construction of two wind power projects in the Province of Quebec using ENERCON wind turbines. Both projects will represent phase one in the potential development of a larger second phase.

Saint-Damase

Phase one of the Saint-Damase wind project is located in the local municipality of Saint-Damase, which is within the regional county municipality of Les Maskoutains. The project is a 24MW facility

located near St. Damase, Quebec in a partnership with the Municipality of Saint-Damase. The Saint-Damase wind project has signed a 20 year PPA with Hydro Quebec and has projected capital costs of $65 million. On June 25, 2013, the partnership executed an interconnection agreement with Hydro Quebec. The permitting and the environmental impact assessment are ongoing and the construction of the first project phase is planned for the early second quarter of 2014, with commercial operation for the project expected to commence in late 2014.

APUC's interest in the project will not be less than 50%. The project's social acceptance is strong and about 50 jobs will be created during construction. The environmental impact assessment for the project has been reviewed and has received the provincial minister's decree allowing the project to proceed with construction. APUC has entered into an agreement for the supply of wind turbines with Enercon Canada Inc. It is believed that the first 24MW phase of the Saint-Damase wind project will qualify as Canadian Renewable Conservation Epense and therefore the project will be entitled to a refundable tax credit equal to approximately $20.5 million. It is contemplated that a request for a PPA in respect of Phase II of the project will be submitted to Hydro Quebec pursuant to its current request for proposals and if successful would proceed based on the results achieved in Phase I.

Val-Éo

Phase one of the Val-Éo wind project is located in the local municipality of Saint-Gideon de Grandmont, which is within the regional county municipality of Lac-Saint-Jean-Est. The project proponents include the Val-Éo wind cooperative formed by community based landowners and APUC. The first 24 MW phase of the project is expected to be comprised of eight wind turbines, producing approximately 66,000 MW-hr annually. Construction of the first 24 MW phase of the project is expected to begin in early 2015 with commercial operations commencing in late 2015. 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 at the end of 2014.

APUC's interest in the project is subject to final negotiations with the Val-Éo community cooperative but, in any event, will not be less 25%. It is believed that the first 24MW phase of the Val-Éo wind project will qualify as Canadian Resource Conservation Expense and therefore the project will be entitled to a refundable tax credit equal to approximately $22.0 million. It is contemplated that a request for a PPA in respect of Phase II of the project will be submitted to Hydro Quebec pursuant to its current request for proposals and if successful would proceed based on the results achieved in Phase I.

(5) Cornwall Solar Project

In the first quarter of 2012, APUC acquired all of the issued and outstanding shares of Cornwall Solar Inc. (**Cornwall Solar**") which owns the rights to develop the Cornwall Solar project, a 10 MW solar project located near Cornwall, Ontario. In addition to the Cornwall Solar project, APUC has acquired an option to acquire ten additional Ontario based solar projects.

The Cornwall Solar project has been granted a 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. The Cornwall Solar project contemplates the use of a ground-mounted PV array system, installed on two parcels of leased land totaling approximately 138 acres.

The Cornwall Solar project received its Renewable Energy Approval on January 15, 2013 and its Notice to Proceed on April 29, 2013. Construction of the project began during the second quarter of 2013 with substantial completion expected by February 28th, 2014 and commercial operation expected to commence late in the first quarter of 2014. After completion of the design and start of construction, improvements in engineering layout and module capacity have led to an increase in annual energy production forecast from 13.4 GW-hrs/year to 14.4 GW-hrs/year. Generation in excess of 13.4 GW-hrs/year is paid to the original developer after minimum return thresholds are achieved by APUC.

(6) Bakersfield Solar Project

APUC entered into an agreement for the continuing development of a 20MWac solar powered generating facility 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 US$4.7 million. APUC plans to enter 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. It is anticipated that the total expected capital costs for the project of US$58.5 million will be funded as to 55% by APUC and the balance by the Tax Partner. Subject to receipt of final permits and approvals and reaching satisfactory agreement with the Tax Partner, construction of the project is anticipated to commence in the second quarter of 2014 with a commercial operations date expected to occur in late 2014.

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

APUC 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.

(g) **Utilities: Water and Wastewater**

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

A 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 from the house or commercial space to the street which line is owned and maintained by the customer. 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 2% 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**

The principal markets of Liberty Utilities’ water and wastewater facilities are located in the United States of America and currently owns utilities operating in the states of Arizona, Texas, Missouri and Arkansas. 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 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. Liberty Utilities 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 Corporate 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 Texas Commission on Environmental Quality (the "**TCEQ**") is the primary regulatory agency with jurisdiction over water and wastewater treatment utilities in Texas. The TCEQ also 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.

(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 Gold Canyon Water System is owned by a wholly-owned subsidiary of Liberty Utilities.

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 sections of the

cities of Goodyear and Avondale. The LPSCo System is owned by a wholly-owned subsidiary of Liberty Utilities.

The LPSCo System presently serves approximately 18,200 water and 20,200 wastewater connections. The wastewater system has permitted capacity of 4.1 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. In 2007, in response to high growth in connections, the LPSCo System began preparing design plans for expansion of its wastewater treatment facility. The capacity expansion was completed at the end of 2012, and final permitting is in process will increase the rated capacity to 5.1 million GPD from 4.1 million GPD. The LPSCo System now operates at approximately 70% of design capacity. The LPSCo System supplies Class “A+” effluent to a number of local golf courses in the area.

On February 28, 2013, LPSCo System filed a general rate case with the Arizona Corporation Commission related to the LPSCo System seeking, among other things, an increase in EBITDA by U.S. $3.0 million over the 2012 results if approved as filed. The application seeks recognition of increased capital investment and increased operating expenses over current rates. In addition to a revenue increase, the application seeks 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. New rates are expected to be implemented in the first half of 2014.

The LPSCo System currently has outstanding indebtedness to the City of Goodyear in the amount of U.S. $10.4 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, 2013 of U.S. $3.2 million bearing an average interest rate of 5.95%. The second series was issued in 2001 with a principal amount as of December 31, 2013 of U.S. $7.0 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, 2013 was U.S. $1.2 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 is owned by a wholly-owned subsidiary of Liberty Utilities.

The Rio Rico System has separate water and wastewater Certificates of Convenience and Necessity and is regulated by the ACC.

On May 31, 2012, the Liberty Utilities region filed a general rate case with the Arizona Corporation Commission related to the Rio Rico 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.

(4) Pine Bluff Water System

Liberty Utilities (Pine Bluff Water) Inc., a subsidiary of Liberty Utilities, is a regulated water utility located in the City of Pine Bluff, Arkansas in Jefferson County with approximately 17,700 service connections and serves a population of over 50,000 people. It is regulated by the Arkansas Public Service Commission and has a franchise agreement with the City of Pine Bluff, Arkansas.

(h) **Liberty Utilities: Electrical Distribution**

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

Electric distribution is the final stage in the delivery system of 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 connections 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 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 the Liberty Utilities (West) and Liberty Utilities (East) regions are subject to state regulation and rates charged by these utilities may be reviewed and approved by their respective State regulatory authorities.

(ii) **Principal Markets**

The principal markets are currently in California and New Hampshire where the utilities operate under a cost-of-service methodology. The utilities use a test year in the establishment of their rates and pursuant to this method the determination of the return on approved rate base, recovery of depreciation, together with operating costs, establishes the revenue requirement upon which the utility's customer rates are determined.

Rate cases ensure that a particular utility 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 utility operates. Liberty Utilities monitors the rates of return on its utility investments to determine the appropriate times to file rate cases in order to ensure it earns the regulatory approved 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 Liberty Utilities' electric distribution utilities is attached in Schedule D.

(1) California

The California Public Utilities Commission ("**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 support 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 47,800 connections. The connection base is heavily-weighted towards El Dorado and Placer Counties, which counties comprise approximately 55% of total revenues.

Connection Base

CalPeco Electric System's connection base 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.

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.

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.

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 million of ten year 5.19% notes and U.S. $25 million of 5.59% fifteen year notes.

(2) Granite State Electric System

The Granite State electric system (the "**Granite State Electric System**") provides distribution service to approximately 43,800 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 37,300 connections, while the commercial and industrial customer base represents approximately 6,500 connections. The commercial and industrial connections are a mix of commercial, retail, medical, education and manufacturing with its largest 10 connections representing approximately 20% of its total annual sales. Its largest customers are a world renowned medical facility and an Ivy League educational institution.

Rate Case

On March 29, 2013, the Granite State Electric System filed a rate case with the 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. The filing was based on a 2012 test year, with revenues and expenses adjusted to reflect known and measurable changes. Among other things, the Granite State Electric System requested and received approval to continue the current cost-recovery tracking mechanism related to the Reliability Enhancement and Vegetation Management Plan and was granted an annual rate increase of U.S. $0.4 million starting July 1, 2013. The Granite State Electric System also requested a modification to allow for recovery of pre-staging personnel and equipment for qualifying storms. On June 27, 2013, the NHPUC approved a settlement agreement authorizing a temporary annual rate increase of U.S.$6.5 million effective July 1, 2013, and provides recognition for Liberty to request an increase to its storm recovery adjustment factor. On January 22, 2014, the Granite State Electric System entered a settlement with the NHPUC Staff, which will provide for a rate increase of U.S.$10.9 million consisting of U.S. $9.8 million in base rates and an additional U.S. $1.1 million for incremental capital expended after the test year. In addition, the settlement allows for one time recovery of rate case expenses of U.S. $0.4 million. It is anticipated that the settlement will be approved late in Q1 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 Independent System Operator - New England (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 at least twice a year, but may do so more frequently if needed to adjust for market prices of power purchased.

Financing

The Granite State Electric System currently has outstanding indebtedness in the form of senior unsecured notes consisting of three tranches for an aggregate amount of $15.0 million: U.S. $5 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.

(i) **Liberty Utilities: Natural Gas Distribution**

(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.

Natural gas reaches Liberty Utilities' natural gas distribution utilities in New Hampshire, Missouri, Iowa, and Illinois through respective city gate stations, where it is measured and injected with an odorant for safety, then distributed to customers through Liberty Utilities' local distribution system of steel and plastic pipelines. The natural gas is sourced from various providers including contracts for natural gas via pipeline as well as liquefied natural gas distributed through its local peak shaving plants.

The gas distribution utilities owned by Liberty Utilities 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**

The principal markets are currently in Illinois, Iowa, Missouri, Georgia, Massachusetts and New Hampshire and operate under a cost-of-service regulation. The natural gas utilities use 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, recovery of depreciation on facilities, together with all reasonable and prudent operating costs, establishes the revenue requirement upon which the 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. Liberty Utilities monitors the rates of return on its utility investments to determine the appropriate times 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 Liberty Utilities' 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 are 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 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 procedural hearing on the issues, the NHPUC sets Cost of Gas Rates.

(2) Illinois

The Illinois operations of Liberty Utilities 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 Iowa operations of Liberty Utilities 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 Missouri operations of Liberty Utilities are regulated by the Missouri Public Service Commission ("**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 Georgia operations of Liberty Utilities are regulated by the Georgia Public Service Commission ("**GAPSC**").

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

In Massachusetts, the operations of Liberty Utilities 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. Liberty Utilities 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 91,100 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 82,000 connections, while the commercial and industrial customer base represents approximately 9,100 connections. The commercial and industrial customer base is a diversified mix of retail, medical, educational and industrial uses. No one connection represents more than 3% of its connection base.

Rate Case

The EnergyNorth Gas System’s last rate case was filed on February 26, 2010. As part of a negotiated settlement, the utility was allowed to increase its base rates by $6.8 million utilizing a

weighted rate of return of 8.33%. The order was approved on March 10, 2011. The order further provided for a bad debt mechanism, permitting EnergyNorth Gas System to recover bad debt subject to limited disallowances, including a potential threshold that would allow it to fully reconcile the commodity portion of its bad debt.

In accordance with the rate case settlement, EnergyNorth Gas System agreed to a stay out period for its next distribution rate case filing (subject to certain conditions) for a period of 3 years from the date of the acquisition by Liberty Utilities, or at least 270 days after EnergyNorth Gas System had successfully transitioned off at least 70% of the services provided by National Grid under the transition service agreements, whichever occurred sooner.

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 85,600 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 23,200 connections in Illinois, 4,500 connections in Iowa and 57,900 connections in Missouri with a mix of residential, commercial, industrial and transportation customers. Of the 85,600 connections, approximately 76,200 (89%) are residential connections, while 9,400 (11%) are commercial and industrial connections. The commercial and industrial connection base is a diversified mix of retail, medical, education and industrial uses.

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.

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 November) 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 utility providing natural gas distribution services to approximately 58,900 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 Peach State Gas System has a distribution system consisting of 1,200 miles of distribution pipelines, 70 miles of transmission pressure gas pipelines and four city gate stations, or distribution supply points.

Customer Base

The Peach State System's customer base consists of a mixture of residential, commercial, industrial and transportation customers. The system's residential customer base represents approximately 54,600 connections, while the commercial and industrial customer base represents approximately 4,400 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 through a special privatization contract.

Rate Case

The Peach State 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 (“ROE”) 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. The most recent GRAM filing has been delayed two months pending the negotiation of a rate smoothing adjustment requested by the GAPSC. The impact of the adjustment will have no adverse impact on the utility and the anticipated rate effective date is now April 1, 2014.

The Peach State Gas System also files an annual Pipe Replacement Program (“PRP”) 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 three years at which time the spending 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 56,100 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 52,400 connections, while the commercial and industrial customer base represents approximately 3,700 connections.. New England Gas System's distribution network consists of 609 miles of distribution main and 35,660 service lines. The New England Gas Systems receives gas at five delivery points or gate stations along the Algonquin Gas Transmission Company (Spectra Energy) transmission system.

Rate Case

New England Gas System's last rate case was filed with the Massachusetts Department of Public Utilities 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 New England Gas System was 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.

3.3 Business Associations with APMI and Senior Executives

Ian Robertson and Chris Jarratt (the "**Senior Executives**") are indirect shareholders of Algonquin Power Management Inc., the former manager of the Corporation 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 the 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" within this section refers to a Committee comprising the independent members of the Board as defined in National Instrument 58-101. 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 fair market valuations of the generating assets, tax and legal matters.

The process initiated in 2011 has been completed and all related party transactions between APUC and the Parties have been resolved 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 the Senior Executives:

Due to and from related parties

As at December 31, 2013, amounts due from related parties were nil (December 31, 2012 - $0.8 million) owed to APUC from the Parties and amounts due to related parties were nil (December 31, 2012 - $1.8 million) owed to the Parties.

Prior to 2010, APMI was the manager of APCo and at the time of the internalization of management, had a number of fees under negotiation as described below:

- APMI was one of the original developers of the Red Lily Wind Facility and was entitled to a royalty fee based on a percentage of operating revenue and a development fee from the equity owner of the Red Lily Wind Facility. In 2011, APUC acquired APMI's interest in this royalty.
- As part of the project to re-power the Sanger Thermal Facility, APUC entered into an agreement with APMI to undertake certain construction management services on the project for a performance based contingency fee.
- During 2007, APUC allowed its offer to acquire Clean Power Income Fund to expire and earned a termination fee for which APMI was entitled to a portion thereof.
- During 2008, APMI provided construction supervision services for the construction of BCI Thermal Facility and was entitled to a construction supervision fee relating thereto.
- During 2009, APMI provided management services to APUC for which fees were earned but not paid. In the provision of these management services, APMI incurred and was also entitled to reimbursement of reasonable expenses in 2009 which were not reimbursed by APUC.

Resolution: The Independent Board Committee and the Parties entered into a definitive agreement on November 15, 2013 whereby APUC agree to pay the Parties $1.8 million in connection with outstanding fees and the Parties agreed to pay APUC $0.8 million in connection with reimbursement of expenses both in full satisfaction of the related party balances. The balances have been fully settled as at December 31, 2013.

The aforementioned transaction was completed by December 31, 2013.

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

Prior to December 31, 2013, the Parties owned interests in three power generation facilities in which APUC also had an interest. A brief description of the facilities is provided as follows:

- The Rattle Brook hydro facility is a 4 MW hydroelectric generating facility constructed in 1998 in which APUC owned a 45% interest and the Senior Executives and others held an equity interest in the remaining 55%.
- The Long Sault Hydro Facility is an 18MW hydroelectric generating facility constructed in 1997. APUC acquired its interest in the Long Sault Hydro Facility by way of subscribing to two notes from the original partners. One of the original partners is an affiliate of APMI which was entitled to receive 5% of the equity cash flows commencing in 2014.
- The BCI Thermal Facility is an energy supply facility which sells steam produced from APCo's EFW Facility In 2004, APMI acquired 50 Class B partnership units in BCI equal to 50% of the annual returns on the project greater than 15%.

Resolution: As part of the process to resolve the co-ownership issue of the above noted assets, the Independent Board Committee undertook valuations by independent

consultants which were reviewed and accepted by the Independent Board Committee. APUC and the Parties entered into an agreement whereby APUC would acquire the Parties' shares of Algonquin Power Corporation Inc. which owns a residual equity interest in the Long Sault Hydro Facility and the partnership interest in the BCI Thermal Facility for an amount equal to $3.8 million. In addition APUC and the Parties entered into an agreement whereby the Parties would acquire APUC's 45% interest in the Rattle Brook hydro facility for an amount equal to $3.4 million. APUC earned a fee of $0.4 million from an affiliate of APMI during the year ended December 31, 2013 (2012 -$nil) related to settlement of the related party transactions.

The aforementioned transactions were completed on December 31, 2013.

St Leon LP Units

Third party investors, including affiliates of the Senior Executives previously held 100 Class B limited partnership units issued by the St. Leon LP which is the owner of the St. Leon Wind Facility. The Class B units held by the Senior Executives received cash distributions of $nil and $0.01 million for the three and twelve months ended December 31, 2013 (2012 - $0.05 million and $0.2 million).

Resolution: On January 1, 2013, the Corporation issued 100 redeemable Series C preferred shares and exchanged such shares for the 100 Class B units including 36 units held indirectly by the Senior Executives. The Series C preferred shares provide dividends essentially identical to that expected from the Class B units, as determined by independent consultants retained by the Independent Board Committee. Independent tax, legal and accounting advisors were also retained by the Independent Board Committee to provide advice in relation to the exchange.

As of January 1, 2013, no Senior Executives had any further direct or indirect ownership interest in the St. Leon wind Facility.

Office Facilities

APUC has leased a portion of its head office facilities since 2001 on a triple net basis from an entity partially owned by affiliates of the Senior Executives. The Independent Board Committee conducted independent reviews of the office leasing market and believes the current terms and conditions for the office lease are at fair market value for a building of comparable size and quality. Base lease costs for the three and twelve months ended December 31, 2013 were $0.1 million and $0.3 million (2012 - $0.1 million and $0.3 million).

Resolution: The current office lease for a portion of its head office facilities expires on December 31, 2015. In August 2013, APUC through a wholly owned subsidiary has acquired a new office facility which is suitable for meeting the future head office needs of APUC. Upon occupancy of the new head office facilities which is anticipated to occur in 2014, it is expected that the currently occupied premises will be subleased to third parties and the relationship between APUC and the Senior Executives in respect of office premises will be concluded.

The Board has deemed this related party transaction to have been satisfactorily addressed.

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 interest. In 2004, APUC remitted $1.3

million to an affiliate of APMI as an advance against expense reimbursements (including utilization reserves) for APUC's business use of the aircraft. By the end of 2012 the entire advance had been amortized against expense reimbursements and therefore no amortization expense during the three and twelve months ended December 31, 2013 related to the advance were incurred (2012 - $0.1 million and $0.3 million). During the three and twelve months ended December 31, 2013, APUC reimbursed direct costs in connection with the use of the aircraft of $0.2 million and $0.5 million (2012 - $0.1 million and $0.6 million).

Resolution: As of December 31, 2013, the remaining amount of the advance was $nil (December 31, 2012 - $nil) and as a result the Independent Board Committee is satisfied that the advance arrangement has concluded. The Independent Board Committee and the Parties have agreed that all future utilization of chartered aircraft will be undertaken through third party charter operators at fair market value and under arrangements in which the Senior Executives have no interest.

The Board has deemed this related party transaction to have been satisfactorily addressed.

Operations Services

APUC provides supervisory services on a cost recovery basis for one small hydroelectric generating facility where the Senior Executives hold an equity interest. The fees paid in relation to the supervisory management services were nominal for the three and twelve months ended December 31, 2012 and 2013.

Resolution: This agreement terminated on December 31, 2013.

Trafalgar

APCo owns debt on seven hydroelectric generating 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.

Resolution: In 2004, the Board 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.

The Board has deemed this related party transaction to have been satisfactorily addressed.

3.4 Principal Revenue Sources

As at March 28, 2014, APUC owned, directly or indirectly, debt, equity and royalty and other interests in thirty-four renewable generation facilities and six 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 and 22 water distribution and wastewater facilities. For the year ended December 31, 2013, APUC derived approximately 26.7% of its revenues from its interests in power generation facilities (32.8% in 2012), 24.6% of its revenues from electrical distribution utilities (31.1% in 2012), 38.7% of its

revenues from natural gas distribution utilities (21.7% in 2012), and 8.5% of its revenues from its interests in water distribution and wastewater utilities (13.3% in 2012),

3.5 Specialized Skill and Knowledge

The senior executives of APUC have extensive contacts in the independent power industry in Canada and the United States.

(i) APCo - Power Generation

APCo'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 APCo requires specialized knowledge of hydraulic turbines and their various components. This specialized knowledge is available to APCo in-house.

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

AES requires specialized knowledge of the ISO-NE and the energy markets in Northern Maine. APCo has contracted the services of six personnel who previously performed these services for the vendor of the contracts acquired by AES.

(ii) Liberty Utilities

Liberty Utilities requires specialized knowledge of the utility systems served including electrical, gas or water and waste water distribution. Upon acquiring a new utility system Liberty Utilities will typically retain the existing employees with such specialized skill and knowledge.

In addition, Liberty Utilities is adding additional utility trained personnel at its corporate offices to support the expanded portfolio of utility assets.

3.6 Competitive Conditions

APUC competes for projects and acquisitions with individuals, corporations and institutions (both Canadian and foreign) which are seeking or may seek investments similar to those desired by APUC. Availability of investment funds and an increase in interest in these investments may increase competition for them, thereby increasing purchase prices or development costs. Many of these investors have greater financial resources than those of APUC or operate according to more flexible conditions.

(i) APCo - Power Generation

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.

(ii) **Liberty Utilities**

Liberty Utilities' businesses have geographic monopolies in their service territories and are therefore insulated from competition. Liberty Utilities has developed significant in-house regulatory expertise in order to effectively interact with the state regulators in the various jurisdictions in which it operates. Liberty Utilities 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

3.7 Environmental Protection

APUC's businesses encompass operations which require adherence to environmental standards imposed by regulatory bodies through licences, 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 licences 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, 2013. However it is expected that certain regimes will impact APUC, in terms of increased expenditures, and that these should not affect the competitive position of APUC. 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. 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.

APUC and its subsidiaries have procedures to prevent and minimize any impact of possible oil spills and soil contamination that meet accepted industry practices. APCo's field personnel perform inspections of oil and chemical storage areas at a minimum on a quarterly basis. Liberty Utilities continuously monitors remediation sites where the company has been named as a potential responsible party and maintains close communications with State representatives. All sites will be remediated in accordance to State approved plans. Each of APUC's businesses have 24 hour, 365 day emergency response and spill procedures in place in the event there is a spill.

3.8 Employees

APUC has four employees involved in the management of the Corporation. APCo employs a total of 193 employees. With the exception of 37 employees at the EFW Facility and 4 employees at the Tinker Hydro Facility, the employees of APCo entities are non-unionized.

Liberty Utilities employs a total of 988 employees. Liberty Utilities employees are non-unionized with the exception of: 54 employees at the CalPeco Electric System, 42 natural gas utility employees in the Liberty Utilities (Central) region, and 123 employees working for Liberty Utilities (East) region.

3.9 Foreign Operations

At the current exchange rate, approximately 72% of EBITDA in 2013 and 70% of cash flow from operations is generated in U.S. dollars. Currency fluctuations may affect the cash flow that APUC

will realize from its operations, as certain of its businesses realize revenues and expenses in US dollars.

3.10 Cycles and Seasonality

Power Generation - Hydrology

The hydroelectric operations of APCo are impacted by seasonal fluctuations. 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. It is, however, anticipated that due to the geographic diversity of the facilities, variability of total revenues will be minimized.

Power Generation - Wind

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 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 flow could be impacted.

Power Generation - AES

For AES, demand for energy is primarily affected by temperature. Demand for energy during colder months is generally greater than warmer months as the load served by AES is located in a “winter peaking” region.

Liberty Utilities – Water distribution

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.

Liberty Utilities – Electricity distribution

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. This phenomenon has been seen across the New England region for some time. The competitive market for power supply is managed by the ISO-NE. Liberty Utilities may see fluctuations in the default service price for power 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. In New Hampshire, if Liberty Utilities is successful in achieving its annual energy efficiency targets, it has the opportunity to earn a performance incentive, which is also recovered via the systems benefit charge.

Liberty Utilities – Natural gas distribution

Natural gas demand is driven by the seasonal heating requirements of its residential, commercial, and industrial customers. That is, the colder the weather the greater the demand for natural gas to heat homes and businesses. As such, natural gas demand profiles typically crest in the winter months of January and February and decline in the summer months of July and August.

In Massachusetts, due the revenue decoupling mechanism that was approved in the last rate case, the New England Gas System's earnings are insulated from the loss of sales volumes associated with energy efficiency and varying effects of the weather.

3.11 Customers

The APCo power generation businesses derive their revenues principally from the sale of electricity to large utilities. Liberty Utilities businesses derive their revenues from a diverse residential, commercial and industrial customer base. For the twelve months ended December 31, 2013, APUC's businesses' revenues were derived as follows: PJM Interconnection LLC - 5.0%; Manitoba Hydro - 4.1%; Hydro Quebec – 3.3%; Connecticut Light and Power - 2.6%; electricity sales and distribution – 24.6%; natural gas sales and distribution – 38.7%; water distribution and wastewater treatment facilities – 8.5%; and others - 13.0%%.

3.12 Economic Dependence

The largest customer on a percentage basis is PJM Interconnection LLC, which totalled 5.0% of gross revenues in the year ended December 31, 2013. PJM Interconnection maintains a Aa3 rating issued by Moody's and receivables from PJM Interconnection are invoiced monthly and generally collected within 25 days.

Similarly, the second largest customer on a percentage basis is Manitoba Hydro which totalled 4.1% of gross revenues in the year ended December 31, 2013. This customer maintains an Aa1 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.

3.13 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 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 Social Responsibility ("**CSR**"). Using the Global Reporting Initiative ("**GRI**"), the Corporation formally tracked several GRI indicators during 2013, with plans to publish its first CSR report in 2014. By weaving CSR into decision making the Corporation reduces liability for investors, increases morale of engaged employees, creates an environmentally cleaner community, and enhances the partnership with all of its stakeholders. CSR 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. Examples of APUC's programs supporting the environment include energy efficiency, water usage, habitat impact, greenhouse gas emissions monitoring, waste reduction and spill prevention. The economic branch of the Corporation's CSR efforts incorporates local spending, local hiring, and operational efficiency. The Corporation's commitment to people is demonstrated through our employee training, organizational development, emergency management, health and safety, diversity, 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.

4. RISK FACTORS

The following are certain risk factors relating to APUC's businesses. The following information is a summary only of certain risk factors 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 attempts to proactively manage the risk exposures of its subsidiaries in a prudent manner. APUC ensures that APCo and Liberty Utilities maintain insurance on all of their facilities. This includes property and casualty, boiler and machinery, and liability insurance. It has also initiated a number of programs and policies including currency and interest rate hedging policies 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.

(a) 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 72% of EBITDA in 2013 and 70% of cash flow from operations is generated in U.S. dollars. APUC estimates that, on an unhedged basis, a $0.10 change 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 $16.2 million, or $0.08 per share, on an annual basis.

APUC manages this risk primarily through the use of natural hedges by using U.S. long term debt to finance its U.S. operations. APUC's policy is not to utilize derivative financial instruments for trading or speculative purposes.

(b) Market price risk

APCo

On May 15, 2012, APCo entered into a financial hedge, which expires December 31, 2016 with respect to the Dickson Dam Hydro Facility located in the Western region. The financial hedge is structured to hedge 75% of APCo's production volume against exposure to the Alberta Power Pool's current spot market rates. For the unhedged portion of production, each $10.00 per MW-hr change in the market prices in the Western region would result in a change in revenue of $0.2 million on an annualized basis.

The July 1, 2012 acquisition of the Sandy Ridge Wind Facility included a financial hedge which commenced on January 1, 2013 for a 10 year period. The financial hedge is structured to hedge 72% of the Sandy Ridge Wind Facility's production volume against exposure to the PJM Western Hub current spot market rates. For the unhedged portion of production, each $10 per MW-hr change in the market prices would result in a change in revenue of about $0.3 million for the year.

The December 10, 2012 acquisition of the Senate Wind Facility included a physical hedge which commenced on January 1, 2013 for a 15 year period. The physical hedge is structured to hedge 64% of the Senate Wind Facility's production volume against exposure to the ERCOT North Zone

current spot market rates. For the unhedged portion of production, each $10 per MW-hr change in the market prices would result in a change in revenue of about $1.1 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 production volume against exposure to the PJM Northern Illinois Hub current spot market rates. For the unhedged portion of production, each $10 per MW-hr change in market prices would result in a change in revenue of about $1.1 million for the year.

For the Sandy Ridge, Senate and Minonk Wind Facilities, in the fourth quarter of 2013, APCo entered into unit contingent financial hedges which commenced January 1, 2014 for a one year period. These hedges are structured to hedge all of the production from the facilities in excess of the production covered by the hedges described in the three preceding paragraphs. The hedges do not have a minimum volume commitment and hence the facilities do not bear any market risk associated with production. As a result, APCo has in place for 2014, hedges covering 100% of the energy produced by the Sandy Ridge, Senate and Minonk Wind Facilities.

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 the PJM ComEd Hub current spot market rates. For the unhedged portion of production, each $10 per MW-hr change in market prices would result in a change in revenue of about $1.1 million for the year.

Liberty Utilities

Liberty Utilities does not have exposure to market price risk as rates charged to customers are stipulated by the respective regulatory bodies.

(c) **Credit/Counterparty risk**

APUC and its subsidiaries are subject to credit risk through its trade receivables 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/counterparty risk with respect to its Power Generation business to be significant. Approximately 85% of the Renewable Energy division's revenue, approximately 100% of the Thermal Energy division's revenue, and over 88.1% of APCo's total revenue is earned from large utility customers having a credit rating of BBB or better. The following chart sets out APCo'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
Renewable Energy Division		*(millions)*	
PJM Interconnection LLC	Aa3	33.6	23.1%
Manitoba Hydro	Aa1	27.8	19.1%
Hydro Quebec	Aa2	22.4	15.4%
US Wind Hedge Counterparty	A	12.1	8.3%
Ontario Electricity Financial Corporation	Aa2	11.7	8.0%
Maine Public Service[2]	BBB+	9.4	6.4%
Commonwealth Edison	BBB	7.3	5.0%
Total - Renewable		**$124.3**	**85.3%**
Thermal Energy Division			
Pacific Gas and Electric Company	A3	16.9	48.9%
Connecticut Light and Power	A-	17.6	51.1%
Total - Thermal		**$34.5**	**100.0%**
Total - APCo		**$158.8**	**88.1%**

1 Ratings by Moody's or Standard & Poor's as of February 2014.
2 Maine Public Service is a subsidiary of Emera.

The remaining revenue is primarily earned by Liberty Utilities. Credit risk related to the Liberty Utilities (West) and Liberty Utilities (Central) regions' accounts receivable balances related to the water and wastewater utilities total U.S. $3.3 million which is spread over approximately 93,000 connections, resulting in an average outstanding balance of approximately U.S $35.00 per connection. Liberty Utilities (East) and Liberty Utilities (Central) regions' accounts receivable balances related to the natural gas utilities total U.S. $52.6 million, while the Liberty Utilities (East) and Liberty Utilities (West) regions' accounts receivable balances related to the electric utilities total U.S. $15.7 million. The natural gas and electrical utilities derive over 88% of their revenue from residential customers.

In addition to the counterparty risk related to customer sales outlined above, APCo and Liberty Utilities utilize derivative instruments as hedges of certain financial risks as discussed elsewhere in this AIF. 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. APUC manages counterparty risk by entering into these instruments with counterparties having a credit rating of BBB- or better.

(d) 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 APUC Credit Facility is subject to a variable interest rate. The APUC Credit Facility has no amounts outstanding as at December 31, 2013. As a result, a 100 basis point change in the variable rate charged would not impact interest expense.

- The APCo Credit Facility had $124.6 million outstanding as at December 31, 2013. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $1.2 million annually.
- APCo's project debt at its Sanger Thermal Facility has a balance outstanding of U.S. $19.2 million as at December 31, 2013. Assuming the current level of borrowings over an annual basis, a 100 basis point change in the variable rate charged would impact interest expense by U.S. $0.2 million annually.
- The Liberty Credit Facility had $80.5 million outstanding as at December 31, 2013. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.8 million annually.
- The senior debt facility in respect of the Shady Oaks Wind Facility had $129.8 million outstanding as at December 31, 2013. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $1.3 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.

(e) 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 APCo and Liberty Utilities 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 at each of APCo and Liberty Utilities to meet their liabilities when due.

As at December 31, 2013, APUC and its subsidiaries had a combined $202.6 million of committed and available credit facilities remaining and $13.8 million of cash resulting in $216.4 million of total liquidity and capital reserves.

APUC currently pays a dividend of $0.34 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.

The long term portion of debt totals approximately $1,255.6 million with no significant maturities until 2017. In the event that APUC was required to replace the credit 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.

(f) Commodity price risk

(i) Power Generation

APCo's exposure to commodity prices is primarily limited to exposure to natural gas and electricity price risk.

- APCo's 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.
- APCo's Windsor Locks Thermal Facility's ESA includes provisions which reduce its exposure to natural gas price risk but has exposure to market rate conditions for sales above those to Ahlstrom. 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.
- AES provides short-term energy requirements to various customers at fixed rates. The energy requirements of these customers are estimated at approximately 200,000 MW-hrs in fiscal 2014. While the Tinker Hydro Facility is expected to provide the majority of the energy required to service these customers, AES anticipates having to purchase approximately 90,000 MW-hrs of its energy requirements at the ISO-NE spot rates to supplement self-generated energy. The risk associated with the expected market purchases of 90,000 MW-hrs is mitigated through the use of short-term financial energy hedge contracts which cover approximately 65,000 MW-hrs of AES's anticipated purchases over the next 12 months at an average rate of approximately $59 per MW-hr. For the amount of anticipated purchases not covered by hedge contracts, each $10.00 change per MW-hr in the market prices in ISO-NE would result in a change in expense of $0.3 million on an annualized basis.

(ii) Liberty Utilities

Liberty Utilities is exposed to energy price risk in the Liberty Utilities (West) region which is mitigated through a regulatory balancing account. The Liberty Utilities (West) region 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 power purchase agreement 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 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. In the CalPeco Electric System's 2012 general rate case, a revenue decoupling mechanism and a vegetation management memorandum account were agreed upon. 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.

In the Liberty Utilities (East) region, 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, the 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 and quarterly for large customers. The winning bidder is obligated to provide a full requirements service based on the actual needs of the Granite State Electric System’s default service customers. Since this is a full requirements service, the winning bidder(s) take on the risk associated with fluctuating customer usage and commodity prices. The supplier is paid for the commodity by the Granite State Electric System which in turns receives pass-through rate recovery through a formal filing and approval process with the NHPUC on a semi-annual basis. The Granite State Electric System is only committed to the winning default service supplier(s) after approval by the NHPUC so that there is no risk of commodity commitment without pass-through rate recovery.

In the Liberty Utilities (East) region, the EnergyNorth Gas System purchases pipeline capacity, storage and commodities from a variety of counterparties. The EnergyNorth Gas System's portfolio of assets, planning and forecasting methodology is approved by the NHPUC bi-annually through an Integrated Resource Plan filing. In addition, the EnergyNorth Gas System files with the NHPUC for recovery of its transportation and commodity costs through a semi-annual winter and summer COG filing and approval process. The EnergyNorth Gas System establishes rates for its customers within the COG filing and these rates are designed to fully recover its anticipated transportation and commodity costs. In order to minimize commodity price fluctuations, the EnergyNorth Gas System has implemented a NHPUC approved commodity hedging program designed to hedge approximately 60% of its non-storage related commodity purchases. All gains and losses associated with the hedging program are allowed to be passed-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 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 carrying costs to the next year’s period COG filing, i.e. winter to winter and summer to summer.

The Liberty Utilities (Central) region purchases pipeline capacity, storage and commodities 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 Liberty Utilities (Central) region 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 Liberty Utilities (Central) region has implemented a commodity hedging program designed to hedge approximately 25 to 50% of its non-storage related commodity purchases. All gains and losses associated with the hedging program are allowed to be passed-through to customers through the PGA filing and

are embedded in the approved rates in said filing. The Liberty Utilities (Central) region may adjust its rates 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.

4.2 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.

(a) Risks Inherent to APUC's Businesses

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.

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.

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.

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 adequate insurance and the establishment of reserves for expenses.

(b) 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 $9.5 million in its financial statements which was assumed in 2013 in conjunction with recent acquisitions.

APCo

Generally, APCo'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 APCo 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. APCo 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 APCo has facilities, APCo 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.

The owners of the St. Leon Wind Facility and the St. Leon II Wind Facility do not own the property on which the turbines 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 APCo

at its option. While APCo anticipates being in a position to renew or extend the existing PPA in 2025, in the event that APCo is unable to renew or extend the agreement, or identify another purchaser of the energy, APCo may choose to decommission the facility. APCo 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.

The owners of the U.S. Wind Portfolio Facilities and Shady Oaks Wind Facility do not own the properties on which the turbines 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 APCo 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, APCo recorded an asset retirement liability of $9.5 million as at December 31, 2013.

Liberty Utilities

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, Liberty Utilities 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 Liberty Utilities is allowed to earn a return on its investment.

Liberty Utilities 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, Liberty Utilities 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 Liberty Utilities is allowed to earn a return on its investment.

Liberty Utilities 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, Liberty Utilities 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 Liberty Utilities is allowed to earn a return on its investment.

(c) **Environmental Risks**

APCo

The APCo 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, APCo 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. As part of the federal and provincial approval of the St. Leon Wind Facility, certain pre-construction and post construction monitoring studies were required. No significant issues were identified as a result of these studies. In order to monitor and mitigate these risks, APCo 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 APCo 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, APCo 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, APCo maintains continuous emissions monitoring systems, performs annual stack testing and completes an annual technical evaluation of ash composition.

Liberty Utilities

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, Liberty Utilities 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 Environmental Protection Agency ("EPA") and state standards. In order to monitor and mitigate these risks, and to remain within the regulatory requirements appropriate for the specific facility, Liberty Utilities 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, Liberty Utilities 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, Liberty Utilities 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. Liberty Utilities 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, Liberty Utilities 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.

Within the Liberty Utilities (East) region, one ongoing environmental risk is currently being monitored.

The EnergyNorth Gas System and Granite State Electric System have been named as a potentially responsible party for remediation at eleven sites and two sites, respectively, which hazardous waste is alleged to have been disposed as a result of historic operations predating Liberty Utilities' acquisition of the utilities. The EnergyNorth Gas System alleged disposal is related to manufactured gas plants ("MGP") and related facilities which date back to the late 1800 to early 1950s, Granite State Electric System sites are related to alleged disposal of PCB contaminated mineral oil. APUC is currently investigating and remediating, as necessary, those site investigation and remediation ("SIR") sites in accordance with plans submitted to the New Hampshire Department of Environmental Services and other agencies. APUC believes that obligations imposed on it because of those sites will not have a material impact on its results of operations or financial position as the clean-up costs are recoverable through rates charged to the customers of the utilities.

Liberty Utilities estimates the remaining cost of these MGP-related environmental cleanup activities will be $77.7 million, which at discount rates ranging from 3.8% to 4.5%, represents $69.6 million at December 31, 2013, which has been accrued as Liberty Utilities' estimate of costs for known issues. By rate orders, the regulator provided for the recovery of SIR costs.

(d) **Cycles and Seasonality Risk**

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

(e) **Specific Environmental Risks**

(i) **APCo - 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 100 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. $6,000 and U.S. $12,000 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 $2.00/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 the EFW Facility in Ontario 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. Once a GHG emissions reduction program is in place, APEFW will be required to purchase emissions allocations based on emissions reported, depending on the timing of the implementation of the Provincial program. The EFW Facility submitted the first GHG report under the Ontario Regulation 452/09 in June 2011. In the future, APEFW will also be required to purchase emissions allocations based on emissions reported for the 2010 and/or subsequent periods, depending on the timing for the implementation of the provincial cap-and-trade program, still under final design and approval.

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 2014.

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 will be compiled in the second quarter of 2014. 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) **Liberty Utilities (West)**

The LPSCo System operates where groundwater pollutants, namely trichloroethylene ("**TCE**") originally employed 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 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 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 System wells. Remedial efforts are currently being intensified in the northwestern portion of the plume in order to ensure full capture of the plume. 2011 remedial efforts continue to demonstrate success with a reduction in the threat of contamination at the LPSCo 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 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 needs of all of the LPSCo System's customers.

In addition, the LPSCo 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. Liberty Utilities 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, 2013.

(iii) **Liberty Utilities (East)**

The most active sites currently under the management of the Liberty Utilities (East) region include the following:

(1) Concord MGP

EnergyNorth Gas System received a notice letter from the New Hampshire Department of Environmental Services (**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 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 June 2014, EnergyNorth Gas System will submit its Remedial Action Plan and application for a Groundwater Management Permit.

(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 ("**CVPS**").

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 at the Liberty Hill Road disposal area, 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.

(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.

(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 March 2014, EnergyNorth Gas System submitted its Remedial Action Plan and applied for a Groundwater Management Permit.

(f) **Regimes that Could Impact APUC**

APCo

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.

Liberty Utilities (West)

The State of California is considering legislation that will increase the Renewable Portfolio Standards to 33% from the current 20% by the year 2020, which could negatively impact the source of electricity for the CalPeco Electric System. Any increases in the cost of electricity will be passed on to the ratepayers through the General Rate Case process.

(g) **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.

(h) **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.

(i) **Tax Related Risks**

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.

(j) **Tax Risks Associated with the Unit Exchange**

There is a possibility that the Canada Revenue Agency could successfully challenge the tax consequences of the Unit Exchange or prior transactions of the Corporation or that legislation could be enacted or amended resulting in different tax consequences from those contemplated in the Unit Exchange for APUC. While APUC is confident in its position, such a challenge or legislation could potentially and materially affect the availability or amount of the tax attributes or other tax accounts of APUC.

(k) **Obligations to Serve**

APCo

APCo is not subject to obligations to serve.

Liberty Utilities

Liberty Utilities 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, Liberty Utilities 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.

APCo

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 licences or permits, including renewals thereof or modifications thereto, may adversely affect cash generated from operating activities.

In the United States, FERC issues licences for the construction, operation and maintenance of hydroelectric generating facilities. Hydroelectric generating facilities are required to be licenced or have valid exemptions from FERC. Failure to maintain such licences, including amendments or modifications thereto, may result in the owner being unable to operate the licenced 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. The ability to sell power at Avoided Cost in the U.S. is dependent on the facility maintaining its qualifying facility status ("**QF Status**") while the ability to sell power at market-based rates is contingent upon either maintaining (i) QF Status and producing no more than 20MW or (ii) market-based rate authority from FERC. Should a facility lose its QF Status or market-based rate authority, it would be required to sell power under a cost-of-service model, which is a more regulated methodology.

Liberty Utilities

Liberty Utilities' water distribution and wastewater collection and treatment utility systems, natural gas distribution utility systems and electric distribution utility systems 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. Federal, State and local environmental laws and regulations impose substantial compliance requirements on utility operations. Operating costs could be significantly affected in order to comply with new or stricter regulatory requirements.

Utilities could be subject to condemnation or other methods of taking by government entities under certain conditions. While any taking by government entities would require compensation be paid to Liberty Utilities, and while Liberty Utilities 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.

Liberty Utilities regularly works with these authorities to manage the affairs of the business.

4.4 Dependence upon APUC Businesses

APUC is entirely dependent upon the profitable operations and assets of other APUC's businesses in order to obtain funding for future growth acquisitions. Accordingly, dividends to shareholders are dependent upon the ability of each of APUC's businesses to pay principal and interest on the notes issued by it and to declare and pay dividends.

4.5 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.

4.6 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.

APCo

With the exception of the EFW Facility and the Tinker Hydro Facility, employees of APCo and their material subcontractors are non-unionized. The EFW Facility has a pending buyer and APUC has requested a six month extension of the collective agreement so the new owner can renegotiate a new contract in 2014. The Tinker Hydro Facility is unionized and a new collective bargaining agreement was renegotiated in January 2011 for a term of five years from 2011 to2015.

Liberty Utilities (West)

In California, 54 employees at the CalPeco Electric System are unionized. The current collective bargaining agreement with the International Brotherhood of Electrical Workers (“IBEW”) was renegotiated in August 2011 for a term of three years, until August 2014. The CalPeco Electric System has good relations with the IBEW union. Internal discussions have begun in preparation for negotiation meetings later with the union. All employees at the water and wastewater utilities in Arizona are non-union.

Liberty Utilities (Central)

In Missouri, there is one union contract with the IBEW covering 41 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. The other employees at the Midstates Gas System, and all employees of Liberty Utilities’ water and wastewater utilities in Arkansas, Illinois, Missouri, and Texas are non-union.

Liberty Utilities (East)

In New Hampshire, there are currently four union contracts with a fifth contract to be put in place in 2014. The United Steelworkers of America ("**Steelworkers**") represent approximately 82 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 36 field employees. The contracts for these groups will expire in May 2014. There are also two 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 15 members. Negotiations are underway with the Steelworkers for an initial contract, and negotiations are proceeding well and are expected to be resolved shortly.

In Massachusetts, the UWUA currently represents 69 employees. Negotiations on the impact of the sale were recently successfully concluded. There is a two year extended contract in effect which will expire on April 30, 2015.

4.7 Dependence Upon Key Customers

APCo

The customers of APCo's power generation 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.

Liberty Utilities

The customers of Liberty Utilities 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, Liberty Utilities is not dependent upon a few key customers.

4.8 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, 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.

4.9 Construction / Development Risk

Successful development of wind and other energy projects are subject to significant risks and uncertainties including those relating to the ability to obtain financing on acceptable terms, receipt of all required permits, currency fluctuations affecting the cost of major capital components such as turbines, price escalation for construction labour and other construction inputs, construction risk that the project is built with mechanical defects, is not completed on time and is not constructed within budget estimates.

4.10 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 APCo and Liberty Utilities 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 APCo and Liberty Utilities.

5. DIVIDENDS

Common Shares

The total amount of dividends declared on the Common Shares for fiscal 2011, 2012 and 2013 were $32.4 million, $50.2 million, and $68.3 million, respectively. The amount of dividends declared for each Common Share of APUC for fiscal 2011, 2012 and 2013 were $0.27, $0.30 and $0.33, respectively.

APUC follows a quarterly dividend schedule, subject to subsequent Board declarations each quarter. Effective May 9, 2013, the Board established a quarterly dividend of $0.085 or $0.34 per share annually.

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 in 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 noted above. 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. On December 31, 2013, a dividend of $0.2815 per Series A Share was declared.

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, total dividends paid to Series C preferred shareholders totalled $0.6 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. The initial dividend, if declared, will be payable on June 30, 2014.

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 all cash dividends on the 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 March 27, 2014, 43,156,472 million 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, 2013, APUC had 206,348,985 issued and outstanding Common Shares and, as at March 27, 2014, APUC had 206,860,592 issued and outstanding Common Shares.

6.2 Private Placements of Subscription Receipts and 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, and on February 14, 2013, 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 million in cash proceeds from the conversion of the subscription receipts were used at the time of the acquisition closing to fund a portion of the cost of the acquisition;
- On February 14, 2013, in connection with the acquisition of Emera's non-controlling interest in the CalPeco Electric System, APUC issued 3.4 million common shares at a price of $4.72 per share for share proceeds of $16.1 million; 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 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 $38.7 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 December 27, 2012, APUC issued 4,790,000 Common Shares and on February 14, 2013, APUC issued 3,421,000 Common Shares upon conversion of these subscription receipts.

As at March 27, 2014, in total Emera now owns 50,126,766 Common Shares, representing approximately 24.2% 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.

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 will 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 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 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, 2013, APUC had 4.8 million Series A Shares, and 100 Series C preferred shares outstanding.

6.4 Convertible Debentures

(a) Series 1A Debentures

On October 27, 2009, the Corporation issued, in connection with the Unit Exchange, an aggregate of $66,942,750 principal amount of Series 1A Debentures.

On April 7, 2011, APUC provided the holders of its Series 1A Debentures with notice of its intention to redeem for equity, all of the issued and outstanding Series 1A Debentures. Prior to the Series 1A Redemption Date (May 16, 2011), a principal amount of $60,339,000 of Series 1A Debentures were converted into 14,788,975 Common Shares. On the Series 1A Redemption Date, APUC issued and delivered 430,666 Common Shares to the remaining holders of the Series 1A Debentures, representing the number of freely tradable Common Shares obtained by dividing the aggregate principal amount of debentures, by 95% of the current market price of the Common Shares on the Series 1A Redemption Date.

As a result, there were no Series 1A Debentures outstanding subsequent to the Series 1A Redemption Date.

(b) 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.

(c) **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. 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. 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. As at December 31, 2013, a total of 146,813 shares had been issued under the ESPP. For the year ended December 31, 2013, APUC issued 85,410 shares under the ESPP and recorded $0.1 million in compensation expense.

6.6 Directors Deferred Share Units

The Deferred Share Unit Plan provides the opportunity for non-employee directors of APUC to elect annually to receive all or any portion of their compensation in deferred share units ("**DSU**") 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 Common Share. Dividends accumulate in the DSU account and are converted to DSUs based on the market value of the shares. DSUs cannot be redeemed until the director retires, resigns, or otherwise leaves the Board. The DSUs provide for settlement in cash or shares at the election of

APUC. As APUC does not expect to settle the DSU's in cash, these DSUs are accounted for as equity awards.

As at December 31, 2013, a total of 74,786 DSUs had been issued under the Deferred Share Unit Plan. For the year ended December 31, 2013, APUC issued 24,614 DSUs under the Deferred Share Unit Plan.

6.7 Performance Share Units

As at December 31, 2013, APUC had 66,195 outstanding performance share units ("**PSU**") to certain members of management other than senior executives as part of APUC's long-term incentive program. At the end of the three-year performance periods, the number of shares vested can range from 0% to 184% of the number of PSUs granted. Dividends accumulate during vesting periods and 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. As APUC does not expect to settle these instruments in cash, these PSUs will 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.

6.8 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.

As of March 28, 2014 the number of outstanding options is 4,567,129, which is 2.2% 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

(a) 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).

2013	High ($)	Low ($)	Volume (000's)
January	7.52	7.09	11,039
February	7.64	7.21	10,677
March	7.78	7.40	9,493
April	8.07	7.36	7,981
May	8.28	7.69	8,966
June	7.57	6.90	10,691
July	7.39	6.98	9,855
August	6.96	6.61	8,712
September	6.78	6.25	13,869
October	6.83	6.09	15,077
November	6.90	6.55	13,744
December	7.40	6.95	8,659

(b) Preferred 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).

2013	High ($)	Low ($)	Volume (000's)
January	25.75	25.30	488
February	26.02	25.69	124
March	25.99	25.40	176
April	25.80	25.38	171
May	26.00	25.60	103
June	25.89	24.60	196
July	25.05	24.00	121
August	23.95	21.75	112
September	22.95	21.61	135
October	22.56	21.75	113
November	22.25	21.53	106
December	21.75	20.63	190

(c) **Series 3 Debentures**

Series 3 Debentures were listed and posted for trading on the TSX under the symbol "AQN.DB.B". On the Series 3 Redemption Date, the remaining Series 3 Debentures were redeemed. As a result, there are no Series 3 Debentures outstanding subsequent to the Series 3 Redemption Date.

As a result of the redemption there was no trading of the Series 3 Debentures in 2013.

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.

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, 2013, no options were exercised. As at December 31, 2013, APUC had 4,567,129 options issued and outstanding. As at December 31, 2013, 2,466,008 options were exercisable. No options were exercised in 2013 or 2012.

	Number of shares	Weighted average exercise price	Weighted average remaining contractual term
Balance at January 1, 2013	3,750,727	$ 5.25	6.07
Granted	816,402	7.72	8.00
Balance at December 31, 2013	4,567,129	$ 5.70	5.45
Exercisable at December 31, 2013	2,466,008	$ 4.90	4.96

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	24.23%

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	Number of Common Shares	Number of Deferred Share Units
CHRISTOPHER J. BALL Toronto, Ontario, Canada Age: 63	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	24,200	16,790
LINDA BEAIRSTO Oakville, Ontario, Canada Age: 53	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	3,743[1,2,3]	N/A
DAVID BRONICHESKI Oakville, Ontario, Canada Age: 54	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. 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	43,495[1,3,4,5]	N/A
CHRISTOPHER HUSKILSON Wellington, Nova Scotia, Canada Age: 56	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	nil [6]	nil [6]

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from	Number of Common Shares	Number of Deferred Share Units
CHRISTOPHER K. JARRATT[7] Oakville, Ontario, Canada Age: 55	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 a 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.	412,025[1,3,4,5,8]	N/A
KENNETH MOORE Toronto, Ontario, Canada Age: 55	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	18,000	38,073
DAVID PASIEKA Oakville, Ontario, Canada Age: 57	David Pasieka is the President of Liberty Utilities. 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 will be in the distribution, transmission, generation and services 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 organization. Mr. Pasieka holds a Bachelor of Science Degree from the University of Waterloo, Masters of Business Administration from the Schulich School of Business –York University and a Chartered Director designation from McMaster University.	Officer of APUC since September 1, 2011	14,563[1,3,8,9,11]	NA

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from	Number of Common Shares	Number of Deferred Share Units
IAN E. ROBERTSON[7] Oakville, Ontario, Canada Age: 54	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.	432,250[1,3,4,5]	N/A
MIKE SNOW Markham, Ontario, Canada Age: 53	Mike Snow is the President of Algonquin Power Co. 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	3,765[1,3,8,12]	NA
GEORGE L. STEEVES Aurora, Ontario, Canada Age: 64	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	17,241[9]	19,921

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from	Number of Common Shares	Number of Deferred Share Units
GEORGE TRISIC Oakville, Ontario, Canada Age: 53	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	Nil	NA

Notes:

1 Ms. Beairsto and Messrs. Jarratt, Robertson, Bronicheski, Pasieka, and Snow hold 85,000, 267,963, 350,413, 162,917, 146,625, and 146,625 stock options respectively, granted on March 14, 2012. The stock options allow for the purchase of Common Shares at a price of $6.22 per share. One-third of the stock options vests on each of January 1, 2013, 2014, and 2015. Stock options may be exercised up to eight years following the date of grant.

2 Ms. Beairsto holds 90,909 stock options granted on July 28, 2011, that allow for the purchase of Common Shares at a price of $5.74 per share. One-third of the stock options vests on January 1, 2012, 2013, and 2014. Stock options may be exercised up to eight years following the date of grant.

3 Ms. Beairsto and Messrs. Jarratt, Robertson, Bronicheski, Pasieka, and Snow hold 65,854, 228,293, 285,366, 91,463, 72,713, and 72,713 stock options respectively, granted on March 14, 2013. The stock options allow for the purchase of Common Shares at a price of $7.72 per share. One-third of the stock options vests on each of January 1, 2014, 2015, and 2016. Stock options may be exercised up to eight years following the date of grant.

4 Messrs. Jarratt, Robertson, and Bronicheski hold 436,224, 494,388, and 229,593 stock options respectively, granted on August 12, 2010. The stock options allow for the purchase of Common Shares at a price of $4.05 per share. One-third of the stock options vested on each of January 1, 2011, 2012 and 2013. Stock options may be exercised up to eight years following the date of grant.

5 Messrs. Jarratt, Robertson, and Bronicheski hold 335,423, 380,146, and 176,538 stock options respectively, granted on March 22, 2011. The stock options allow for the purchase of Common Shares at a price of $5.23 per share. One-third of the stock options vests on each of January 1, 2012, 2013 and 2014. Stock options may be exercised up to eight years following the date of grant.

6 Mr. Huskilson does not own any Common Shares or Deferred Share Units.

7 Messrs. Jarratt and Robertson, together with others, collectively own all of the issued and outstanding shares of APMI. As consideration for payment of APUC's acquisition of APMI's interest in the management agreement, Mr. Robertson and Mr. Jarratt following shareholder approval each received 295,045 Common Shares.

8 Messrs. Jarratt, Pasieka, and Snow hold 38,548, 15,234, and 15,234 stock options respectively, granted on June 19, 2012. The stock options allow for the purchase of Common Shares at a price of $6.56 per share. One third of the stock options vest on each of January 1, 2013, 2014, and 2015. Stock options may be exercised up to eight years following the date of grant.

9 Mr. Pasieka directly owns 13,583 Common Shares and Mr. Pasieka's spouse owns 980 Common Shares. Mr. Pasieka exercises control and direction over the Common Shares owned by his spouse.

10 Mr. Steeves' directly owns 14,327 Common Shares and Mr. Steeves' spouse owns 2,914 Common Shares. Mr. Steeves exercises control and direction over the Common Shares owned by his spouse.

11 Mr. Pasieka holds 172,242 stock options granted on September 13, 2011. The stock options allow for the purchase of Common Shares at a price of $5.65 per share. One third of the stock options vest on each of January 1, 2012, 2013, and 2014. Stock options may be exercised up to eight years following the date of grant.

12 Mr. Snow holds 171,642 stock options granted on June 21, 2011. The stock options allow for the purchase of Common Shares at a price of $5.64 per share. One third of the stock options vest on each of January 1, 2012, 2013, and 2014. Stock options may be exercised up to eight years following the date of grant.

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 of March 27, 2014, approximately 909,841 Common Shares representing 0.44% of the issued and outstanding Common Shares are beneficially owned, directly or indirectly, by the Senior Executives and approximately 969,282 Common Shares representing 0.47% of the issued and outstanding Common Shares are beneficially owned, directly or indirectly, by the directors and executive officers of the Corporation.

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 Mr. Steeves, 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.

(a) Audit Committee Charter

The charter for APUC's audit committee (the "**Audit Committee**") is attached as Schedule F to this AIF.

(b) 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)

Mr. Steeves is the former President of Cumming Cockburn Limited and has extensive financial experience in acting as a Chairman, director and/or audit committee member of public and private companies, including APCo, Borealis Hydroelectric Holdings Inc. and KMS Power Income Fund.

Mr. Steeves 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). He received a Bachelor and Masters of Engineering from Carleton University and holds the Professional Engineering designation in Ontario and British Columbia.

(c) 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, 2013 and December 31, 2012, Ernst & Young LLP and KPMG LLP charged the following fees to APUC respectively:

Services	2013 Fees ($) (KPMG LLP) [5]	2013 Fees ($) (Ernst & Young LLP)[6]	2013 Total Fees	2012 Fees ($) (KPMG LLP)
Audit Fees[1]	351,000	1,242,000	1,798,688	1,346,100
Audit-Related Fees[2]	—	40,806	40,806	316,925
Tax Compliance Fees[3]	86,575	—	301,000	647,342
Other Tax Fees[4]	141,722	40,000	40,000	495,168
All Other Fees	61,100	—	61,100	25,000

Notes:

1 For professional services rendered for audit or review or services in connection with statutory or regulatory filings or engagements. The 2012 fees include additional costs related to APCo private placement and APUC equity offering.

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 accounting advice and French translation services.

3 For preparation of income and other tax filings.

4 For tax advice 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 three of the directors of APUC, Mr. Steeves (Chair), Mr. Huskilson 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 two directors of APUC, Mr. Huskilson (Chair) and Mr. Ball. 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 and APUC's financial statements and management's discussion and analysis for the fiscal year ended December 31, 2013, 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 2013 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 ("**Aetna**") 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 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. The Second Circuit Cort of Appeals, among other things, on November 2, 2010 dismissed the claims against APUC in the civil proceedings.

With respect to the civil proceedings, the United States Second Circuit Court of Appeals dismissed all the claims against APUC and remanded one issue to the District Court. On April 3, 2012, the

District Court granted APUC summary judgment on its counterclaims 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. 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. 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.

(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., a predecessor company to 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 Hydro 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. had 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.

(iii) Long Sault Global Adjustment Claim

In December 2012, N-R Power & Energy Corp., Algonquin Power (Long Sault) Partnership, and N-R Power Partnership (collectively "**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. Cross examinations were held in November, 2013. A hearing is scheduled for early 2014.

(iv) Dimos and Katsekas breach of contract claim

On September 30, 2013, previous owners of the 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 March, 2015.

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

In June 2013, APFA sold its interests in a partnership that owned the Great Falls hydro facility, located in Passaic, New Jersey. On August 2, 2013, the previous owners of the Great Falls hydro facility filed a complaint against APFA in U.S. District Court for the District of Maryland, seeking $3,000,000 for alleged breach of the purchase agreement by which the Great Falls hydro facility was acquired in 2000 and alleged breach of a related royalty agreement, by reason of the subsequent transfer and failure to pay plaintiffs a transfer payment in connection therewith. On September 25, 2013, APFA filed an Answer and Counterclaim against Synergics, seeking a declaratory judgment that the royalty agreement has been terminated and that APFA owes no further payment to plaintiffs. APFA also filed a motion to dismiss Synergics' claim for attorneys' fees, which is currently pending before the court.

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

On October 31, 2013, the plaintiffs filed a complaint against APUC, APCo and APT in U.S. District Court for the District of South Dakota, alleging, among other things, alleged breach of a confidentiality agreement in relation to the development and construction of the 10-megawatt solar photovoltaic Cornwall Solar project in Ontario, Canada. Plaintiffs served Algonquin with the complaint on February 11, 2014. Algonquin has filed a motion to dismiss the lawsuit on the basis of lack of personal jurisdiction and on the basis of forum non conveniens. The motion is currently pending before the court.

(vii) Senate Wind Facility property tax abatement hold harmless payment claims

Senate Wind, LLC is a party to certain Value Limitation Agreements with the Bryson and Graham Independent School Districts in Texas, relating to property tax abatement for the Senate Wind

Facility. On February 10, 2014, and March 4, 2014 APCo received correspondence from an accounting firm engaged by the School Districts, setting forth their estimate of certain “hold harmless” payments due from Senate Wind, in the amounts of U.S.$2.2 million and U.S.$0.4 million respectively, under the agreements as a result of certain impacts of the initial year of the tax abatement. Senate Wind has objected to the calculation and is seeking additional information from the School Districts pursuant to requirements of the agreements.

9.2 Regulatory Actions

Except as disclosed elsewhere in this AIF, during the financial year ended December 31, 2013, 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, 2013, 2012 and 2011, 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

It is worthy of note that transfer agreements dated December 21, 2009 with each of the principals of APMI that transferred their interests in the management agreement (as discussed in the management information circular dated June 1, 2010) were approved in 2010 by the shareholders at the annual and special meeting of shareholders as well as the TSX. The following previously disclosed material contracts with Management have all been terminated as they pertain to APUC: the management agreement; the operations supervisory agreement; the administration agreement; the governance agreement; and the direct operations agreements.

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 2013 (or prior to 2013 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 SponsorCo and, therefore, 60% of the indirect managing interests in the U.S Wind Portfolio Facilities, in 2012. APFA has agreed to purchase the remaining 40% interest in SponsorCo from Gamesa USA pursuant to a Supplement and Amendment to the MIPSA, dated November 27, 2013 ("**MIPSA Supplement**") between APFA and Gamesa USA.

(b) **Midwest Gas System Acquisition:** An Asset Purchase Agreement entered into on May 12, 2011 between Atmos Energy Corporation, as seller, and Liberty Midstates, as buyer to acquire certain regulated natural gas distribution utility systems located in the States of Missouri, Iowa, and Illinois. Guaranty dated as of May 12, 2011 made by APUC as guarantor, in favour of Atmos. The transaction was completed on August 1, 2012.

(c) **Peach State Gas System Acquisition:** Asset Purchase Agreement entered into on August 8, 2012 between Atmos, as seller, and Peach State, as buyer to acquire certain regulated natural gas distribution utility systems located in the State of Georgia. Guaranty dated as of August 8, 2012 made by APUC as guarantor, in favour of Atmos. This transaction was completed on April 1, 2013.

(d) **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 the Airsource Senior Debt and to reduce outstanding indebtedness under the APCo Credit Facility. Second Supplemental Trust Indenture between APCo and BNY Trust Company of Canada dated December 3rd, 2012 providing for the issuance of $150,000,000 4.82% senior unsecured debentures due February 15, 2021.

(e) **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.

(f) **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 guaranty dated as of December 8, 2010 by APUC as guarantor, in favour of National Grid. The interests of buyer in the a

greements were transferred to Liberty Energy NH, and the transactions were completed on July 3, 2012.

(g) **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.

(h) **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 the connection with a U.S. $225 million private placement of senior notes maturing between July 31, 2017 and July 30, 2027.

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, 2013.

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:** $0.0909/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:** Ontario Power Authority **Rates**: $0.0842/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**: $0.0832/kW-hr	37,650	2016
Facility: Glenford Hydro Facility **Owner**: Societe en Commandite Chute Ford	4,950	Ste-Anne River near the Village of Ste-Christine d'Auvergne, Québec	**Electricity Purchaser:** Hydro-Québec **Rates**: $0.0832/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)	15,400	2014 PPA renewal option has been exercised to extend PPA to 2034[9]
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 $0.0502/kW-hr	Phase 1: 15,500	Phase 1: 2020
			Phase II Energy $0.0710/kW-hr Capacity $174.16/kW *	Phase II: 35,100	Phase II: 2018 PPA has renewal option to 2043
			Phase III Energy $0.0739/kW-hr Capacity $182.60/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)	22,550	2014 PPA renewal option has been exercised to extend PPA to 2034[9]
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**: $0.0612/kW-hr	21,250	2027

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 : 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**: $0.0832/kW-hr	17,250	2015 PPA has renewal option to 2035
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[9]
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)	12,750	2014 PPA renewal option has been exercised to extend PPA to 2034[9]
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	11,250	2013[8] PPA renewal option has been exercised to extend PPA to 2033
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**: $0.0832/kW-hr	20,550	2022 PPA has renewal option to 2047
Facility: Arthurville Hydro Facility **Owner**: Algonquin Power Trust	650	Riviere 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[8] PPA renewal option has been exercised to extend PPA to 2033

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 - New York Facilities					
Facility: Ogdensburg Hydro Facility **Owner**: Trafalgar[2]	3,675	Oswegatchie River near Ogdensburg, New York	**Electricity Purchaser:** National Grid **Rates**: US$0.0377/kW-hr (est)[3]	11,100	2016
Facility: Forestport Hydro Facility **Owner**: Trafalgar[2]	3,300	Black River near Boonville, New York	**Electricity Purchaser:** National Grid **Rates**: US$0.0377/kW-hr (est) [3]	11,500	2016
Facility: Herkimer Hydro Facility **Owner**: Trafalgar[2]	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]	850	Sacandaga River near Clifton, New York	**Electricity Purchaser:** National Grid **Rates**: US $0.0377/kW-hr (est)[3]	3,300	2028
Facility: Cranberry Lake Hydro Facility **Owner**: Trafalgar[2]	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]	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
Facility: Adams Hydro Facility **Owner**: Trafalgar [2]	350	Sandy Creek near Adams, New York	**Electricity Purchaser:** National Grid **Rates**: No target rate as the site is expected to be offline	0[4]	2028

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 - New England Facilities					
Facility: Clement Hydro Facility[7] **Owner**: Clement Dam Hydroelectric LLC	2,400	Winnipisaukee River near the Town of Tilton, New Hampshire	**Electricity Purchaser:** PSNH **Rates**: market rates [5]	—	60 day written notice
Hydroelectric - Western Canada Facility					
Facility: Dickson Dam Hydro Facility **Owner:** Algonquin Power Operating Trust	15,000	Innisfail, Alberta	**Electricity Purchaser:** AESO **Rates**: market rates	65,000	2016[10]
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. $0.0404/kWhr Town of Perth Andover: ~ CDN $0.0835/kWhr	120,000	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. $0.0404/kWhr	5,300	n/a
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. $0.0404/kWhr	850	n/a
Solar Facilities					
Facility: Cornwall Solar Facility **Owner**: Cornwall Solar Inc.	10,000	Cornwall, Ontario	**Electricity Purchaser:** (Under Development - expected to commence commerical operation in Q1 2014) Rates: $.443/kWh	14,400	2034 (20 years after Commercial operation Date)

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: Bakersfield Solar Facility **Owner**: Algonquin SKIC20 Solar, LLC	20,000	Bakersfield, California	**Electricity Purchaser:** (Under Development – PG&E)	53,300	2035
Wind Facilities					
Facility: Minonk Wind Facility **Owner**: Minonk Wind, LLC	200,000	Minonk, Illinois	**Electricity Purchaser:** PJM North Illinois **Rates:** market rates	674,000	2022[(6)]
Facility: Chaplin Wind Facility **Owner**: Windlectric Inc.	177,000	Chaplin, Saskatchewan	**Electricity Purchaser:** (Under Development - SaskPower)	247,000	n/a
Facility: Senate Wind Facility **Owner:** Senate Wind, LLC	150,000	Graham, Texas	**Electricity Purchaser:** ERCOT North markets **Rates:** market rates	520,000	2027[(6)]
Facility: Shady Oaks Wind Facility **Owner:** GSG6, LLC	109,500	Lee County, Illinois	**Electricity Purchaser:** Commonwealth Edison **Rates:** market rates	364,000	2032
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
Facility: Amherst Island Wind Facility **Owner**: Windlectric Inc.	75,000	Stella, Ontario	**Electricity Purchaser:** (Under Development - OPA)	247,000	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: Sandy Ridge Wind Facility **Owner:** Sandy Ridge Wind, LLC	50,000	Tyrone, Pennsylvania	**Electricity Purchaser:** PJM West **Rates:** market rates	158,000	2022[6]
Facility: Red Lily Wind Facility **Owner**: Red Lily Wind Energy Partnership	26,400	Saskatchewan	**Electricity Purchaser:** SaskPower **Rates:** $0.0897/kW-hr	88,000	2036
Facility: Morse Wind Facility **Owner**: Algonquin Power Morse LP	25,000	Morse, Saskatchewan	**Electricity Purchaser:** (Under Development - SaskPower)	93,000	n/a
Facility: Saint-Damase Wind Facility **Owner**: Société en Commandité Fleur de Lis Éoliennes Saint-Damase	24,000	Saint-Damase, Québec	**Electricity Purchaser:** (Under Development – Hydro-Quebec)	86,000	n/a
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
Facility: St. Leon II Wind Facility **Owner**: St. Leon II Wind Energy LP	16,500	St. Leon, Manitoba	**Electricity Purchaser:** Manitoba Hydro	58,000	2,037

Notes:

1. 2013 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. APC 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 2014. No decision has been made as to the timing of repairing these facilities.

5. PSNH purchases the energy produced by these generating stations at the ISO-NE. market rates. These agreements are cancellable on 60 days written notice.

6. 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”.

7. Facility is currently accounted for as discontinued operations as APUC has entered into an agreement to sell the facility with a closing date expected to be the first quarter of 2014.

8. APUC has exercised its option with Hydro-Québec to renew the PPA for a second 20-year term. PPA renewal terms are under discussion.

9. APUC has exercised its option to begin discussions with Hydro-Québec to enter a new PPA agreements expiring in 2014.

10. 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*”.

SCHEDULE B

Thermal - Biomass, Cogeneration, Steam, Diesel and Energy From Waste Facilities

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2014 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: $0.0709/kW-hr	0[1]	2014	Owned
Thermal - Cogeneration Facilities						
Facility: Sanger Facility **Owner**: Algonquin Power Sanger LLC (California)	56,000	Sanger, California	**Electricity Purchaser:** PG&E	140,900	2021	Owned
			Rates: US$ 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$0.1/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			
Facility: Brampton Cogeneration Inc. [2] **Owner**: Algonquin Power Operating Trust	N/A	Brampton, Ontario	**Electricity Purchaser:** N/A **Rates**: Steam - Normapac $6.90/1000lbs* Capacity $104,700** * Estimated average rate, includes variable component based on natural gas prices. **Estimated average monthly rate, charges are partially CPI indexed.	624 million lbs of steam	2024	N/A

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2014 Power Purchase Rates	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of PPA	Lease Expiry Year
Thermal – Energy-from-Waste Facilities						
Facility: EFW Thermal Facility[2] **Owner**: Algonquin Power Energy from Waste Inc.	9,300	Brampton, Ontario	**Electricity Purchaser:** Hydro One Brampton Inc. **Rates**: market rates	5,600	N/A	Owned
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

Notes:

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.
2. Accounted for as discontinued operations for the periods ended December 31, 2013 and December 31, 2012. The facilities have not been classified as discontinued operations in the annual 2012 and 2011 financial statements.

SCHEDULE C

Wastewater and Water Distribution Facilities

Utility	Owner	Location	Type of Utility	December 31, 2013 Connections	Rates[1]
Black Mountain Sewer System	Liberty utilities (Black Mountain Sewer) Corp.	Carefree, Arizona	Wastewater	2,197	Pursuant to ACC decision 71865
Gold Canyon Sewer System	Liberty Utilities (Gold Canyon Sewer) Corp.	Gold Canyon Arizona	Wastewater	7,531	Pursuant to ACC decision 69664
Bella Vista Water System	Liberty Utilities (Bella Vista Water) Corp.	Sierra Vista, Arizona	Water Distribution	9,241	Pursuant to ACC decision 72251
Tall Timbers Waste System	Liberty Utilities (Tall Timbers Sewer) Corp.	Tyler, Texas	Wastewater	2,268	Pursuant to TCEQ decision 2009-1381-UCR and SOAH decision 582-10-0350
Woodmark Waste System	Liberty Utilities (Woodmark Sewer) Corp.	Tyler, Texas	Wastewater	1,796	Pursuant to TCEQ decision on Jan 1, 2010
LPSCo Water & Waste System	Liberty Utilities (Litchfield Park Water & Sewer) Corp.	Litchfield, Park, Arizona	Wastewater Water Distribution	20,179 18,205	Pursuant to ACC decision 72026
Fox River Water & Waste System	Liberty Utilities (Fox River Water) LLC	Sheridan, Illinois	Wastewater Water Distribution	220 220	Per customer agreement[2] US $240.08 US $141.61
Timber Creek Water & Waste System	Liberty Utilities (Missouri Water) LLC	DeSoto, Missouri	Wastewater Water Distribution	20 25	Pursuant to MOPSC decision WR-2006-4025
Holiday Hills Water System	Liberty Utilities (Missouri Water) LLC	Branson, Missouri	Water Distribution	484	Per MOPSC Case WR-2006-4025
Ozark Water & Waste System	Liberty Utilities (Missouri Water) LLC	Kimberling City, Missouri	Wastewater Water Distribution	241 255	Pursuant to MOPSC decision WR-2006-4025
Holly Lake Water & Waste System	Liberty Utilities (Silverleaf Water) LLC	Hawkins, Texas	Wastewater Water Distribution	152 1,949	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	412 681	Pursuant to TCEQ decision 2009-2087-UCR & SOAH decision 582-10-2369

Utility	Owner	Location	Type of Utility	December 31, 2013 Connections	Rates[1]
Piney Shores Water & Waste System	Liberty Utilities (Silverleaf Water) LLC	Conroe, Texas	Wastewater Water Distribution	269 273	Pursuant to TCEQ decision 2009-2087-UCR & SOAH decision 582-10-2369
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	2,222 6,778	Pursuant to ACC decision 72059
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	869	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	694	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	184 545	Pursuant to MOPSC decision WO-2010-0345
Pine Bluff Water System	Liberty Utilities (Pine Bluff Water) Inc.	Pine Bluff, Arkansas	Water Distribution	17,847	Pursuant to APSC decision Docket No. 09-130-U
Total connections[3]				**97,400**	

Notes:

1. See www.libertyutilities.com for complete rate tariffs.
2. Rates charged per agreement with developer.
3. Inclusive of vacant connections.

SCHEDULE D

Electrical Distribution Facilities

Utility	Owner	Location	Type of Utility	December 31, 2013 Connections[2]	Rates[1]
CalPeco Electric System	Liberty Utilities (CalPeco Electric) LLC	Lake Tahoe, California	Electricity Distribution	Residential - 42,200 Commercial & Industrial - 5,560	Rates pursuant to CPUC decision 12-11-030
Granite State Electric System	Liberty Utilities (Granite State Electric) Corp	Salem, New Hampshire	Electricity Distribution	Residential – 37,300 Commercial & Industrial - 6,530	Rates pursuant to NHPUC decision DE 14-031

Notes:

1. See www.libertyutilities.com for complete rate tariffs.
2. Inclusive of vacant connections.

SCHEDULE E

Natural Gas Distribution Facilities[1]

Utility	Owner	Location	Type of Utility	December 31, 2013 Connections[2]	Rates[1]
EnergyNorth Gas System	Liberty Utilities (EnergyNorth Natural Gas) Corp.	Manchester, New Hampshire	Natural Gas Distribution	Residential – 82,045 Commercial & Industrial – 9,095	Rates pursuant to NHPUC decision DE12-265
Peach State Gas System	Liberty Utilities (Peach State Natural Gas) Corp.	Columbus, Gainesville, GA	Natural Gas Distribution	Residential - 54,557 Commercial & Residential - 4,376	Rates pursuant to GPSC Docket #34734 Document #145956
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 - 52,414 Commercial & Industrial - 3,688	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 –21,131 Commercial & Industrial –2,084	Rates pursuant to ICC decision IL-11-0559
Midstates Gas System - Iowa	Liberty Energy (Midstates Natural Gas) Corp.	Keokuk, Iowa	Natural Gas Distribution	Residential –4,055 Commercial & Industrial- 454	Rates pursuant to IUB decision SPU-2011-0008
Midstates Gas System - Missouri	Liberty Energy (Midstates Natural Gas) Corp.	Jackson, Sikeston, Butler, Kirksville, Hannibal, Missouri	Natural Gas Distribution	Residential –51,213 Commercial & Industrial –6,696	Rates pursuant to MPSC decision GM-2012-0037

Notes:

1. See www.libertyutilities.com for complete rate tariffs.
2. Inclusive of vacant connections.

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 Charter 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

1 0 . 1 Currency of Charter – This Charter 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.

"**2011 APCo Debentures**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2011 - APCo - Power Generation - APCo Senior Unsecured Debentures".*

"**2012 APCo Debentures**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2012 – APCo – Power Generation – APCo $150 million Senior Unsecured Debentures".*

"**2014 APCo Debentures**" has the meaning ascribed thereto under "*General Development of the Business - Recent Developments - 2014 - APCo - Power Generation - APCo $200,000,000 Senior Unsecured Debentures*".

"**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".*

"**ACC**" has the meaning ascribed thereto under *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Utilities: Water and Wastewater – Principal Markets - Arizona".*

"**ADEQ**" has the meaning ascribed thereto under *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Utilities: Water and Wastewater – Principal Markets - Arizona".*

"**AES**" means Algonquin Energy Services Inc., a Delaware corporation. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**AESO**" has the meaning ascribed thereto under *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric – Principal Markets and Distribution Methods – Alberta".*

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

"**Ahlstrom**" means Ahlstrom Windsor Locks, LLC

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

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

"**AirSource Senior Debt**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2011 – APCo - Power Generation – APCo Senior Unsecured Debentures".*

AMBOSA" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Power Generation: Renewable - Wind Power - Material Facilities - Sandy Ridge Wind Facility"*.

"**APA**" means Algonquin Power (America) Inc. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**APC**" has the meaning ascribed thereto under *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric – Material Facilities – Long Sault Hydro Facility".*

"**APCI**" means Algonquin Power Corporation Inc. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**APCo**" means Algonquin Power Co. See *"Corporate Structure – Name, Address and Incorporation"*.

"**APCo Credit Facility**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2011 – APCo - Power Generation - APCo Credit Facility Renewal".*

"**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"*.

"**APFC**" means Algonquin Power Fund (Canada) 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"*.

"**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). See *"General Development of the Business – General – Business Strategy"*.

"**APUC Credit Facility**" has the meaning ascribed thereto under "*General Development of the Business – Three Year History and Significant Acquisitions – Recent Developments – Fiscal 2012 – Corporate – APUC Credit Facility".*

"Arthurville Hydro Facility" means the Arthurville hydroelectric generating facility

"**Atmos**" means ATMOS Energy Corporation. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Audit Committee**" has the meaning ascribed thereto *"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 *"Description of the Business – General Description of the Regulatory Regimes in which the Business Operates – Power Generation Regulatory Regimes – United States".*

"**Bakersfield Solar Project**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History Significant Acquisitions - Fiscal 2013 - APCo - Power Generation - Acquisition of the 20 MW ac Bakersfield Solar Project"*.

"**BCI**" means Brampton Cogeneration Inc. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**BCI Thermal Facility**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

Belleterre Hydro Facility" means the Belleterre hydroelectric generating facility.

"**Bill C-93**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Power Generation: Renewable - Hydroelectric - Principal Markets and Distribution Methods - Quebec"*.

"**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 - Production Method, Principal Markets, Distribution Methods and Material Facilities - Liberty Utilities: Electrical Distribution - Principal Markets - California"*.

"**Burgess Hydro Facility**" means the Burgess Dam hydroelectric generating facility.

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

"**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 – General Description of the Regulatory Regimes in which the Business Operates – Water Utility Services Regulatory Regimes".*

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

"**CEO**" means Chief Executive Officer

"**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 – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric – Material Facilities – Long Sault Hydro Facility".*

Clement Dam Hydro Facility" means the Clement Dam hydroelectric generating facility.

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

"**Cochrane Thermal Facility**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Power Generation: Thermal - Cogeneration - Material Facilities - Cochrane Thermal Facility".*

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

"**COG**" has the meaning ascribed thereto under *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – A Liberty Utilities: Electrical Distribution - Material Facilities - Granite State Electric System"*.

"**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 – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable - Hydroelectric - Material Facilities - Long Sault Hydro Facility".*

"**Cornwall Solar**" means Cornwall Solar Inc. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – APCo: Development Division – Current Development Projects – Cornwall Solar"*.

"**Côte Ste.-Catherine Hydro Facility**" means the Côte Ste-Catherine hydroelectric generating facility.

"**CPUC**" has the meaning ascribed thereto under *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Liberty Utilities: Electrical Distribution – Principal Markets – California"*.

"**CVPS**" *has the specific meaning ascribed thereto under "Risk Factors" - Operational Risk Management - Specific Environmental Risks".*

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

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

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

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

"**ECAC**" has the meaning ascribed thereto under *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Liberty Utilities: Electrical Distribution – Principal Markets – California"*.

"**EFW Facility**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**Electricity Act**" has the meaning ascribed thereto under *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric – Principal Markets and Distribution Methods – New Brunswick and Northern Maine".*

"**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 *"Risk Factors – Operational Risk Management – Environmental Risks".*

"**ERCOT**" has the meaning ascribed thereto under *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Wind Power – Principal Markets and Distribution Methods"*

"**ESA**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2011 – APCo – Power Generation – Windsor Locks Repowering".*

"**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 – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric – Principal Markets and Distribution Methods – Alberta".*

"**EWGs**" has the meaning ascribed thereto under *"Description of the Business - General Description of the Regulatory Regimes in which the Business Operates - Power Generation Regulatory Regimes - United States - PUHCA"*.

"**FERC**" has the meaning ascribed thereto under *"Description of the Business – General Description of the Regulatory Regimes in which the Business Operates – Power Generation Regulatory Regimes – United States".*

"**FIT**" has the meaning ascribed thereto under *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – APCo: Development Division – Principal Market Environment"*.

"**FPA**" has the meaning ascribed thereto under *"Description of the Business – General Description of the Regulatory Regimes in which the Business Operates – Power Generation Regulatory Regimes – United States".*

"**FVCO**" has the meaning ascribed thereto under *"Description of the Business - General Description of the Regulatory Regimes in which the Business Operates - Power Generation Regulatory Regimes - United States - PUHCA"*.

"**GAPSC**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Liberty Utilities: Electrical Distribution - Material Facilities - Granite State Electric System"*.

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

"**Gold Canyon Water System**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Utilities: Water and Wastewater - Material Facilities - Gold Canyon Water System".*

"**Goldwind**" has the meaning ascribed thereto under "*General Development of the Business - Three Year History and Significant Acquisitions - Recent Developments - 2013 - APCo - Power Generation - Acquisition of Shady Oaks Wind Facility".*

"**gpd**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Utilities: Water and Wastewater - Material Facilities - Gold Canyon Water System".*

"**GRAM**" has the meaning ascribed thereto under *"Description of the Business - Production Methods, Principal Markets, Distribution Methods and Material Facilities - Liberty Utilities: Natural Gas Distribution - Material Facilities - Peach State Gas System"*.

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

"**Granite State Electric System**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Liberty Utilities: Natural Gas Distribution - Principal Markets - Illinois"*.

"**GRI**" has the meaning ascribed thereto under "*Description of the Business - Safety 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 Snemo Facility**" means the Hydro Snemo hydroelectric generating facility.

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

"**ICC**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Liberty Utilities: Electrical Distribution - Material Facilities - Granite State Electric System"*.

"**Independent Board Committee**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2013 - Related Party Transactions"*.

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

"**ISO-NE**" has the meaning ascribed thereto under the heading *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Power Generation: Thermal - Cogeneration - Principal Markets and Distribution Methods - Connecticut".*

"**ITC**" or "**Investment Tax Credit**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - APCo: Development Division - Principal Market Environment"*.

"**IUB**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Liberty Utilities: Electrical Distribution - Material Facilities - Granite State Electric System"*.

"**JPMVEC**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Power Generation: Renewable - Wind Power - Material Facilities - Sandy Ridge Wind Facility"*.

"**Kirkland**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Power Generation: Thermal - Cogeneration - Material Facilities - Kirkland Thermal Facility".*

"**Kirkland Thermal Facility**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Power Generation: Thermal - Cogeneration - Material Facilities - Kirkland Thermal Facility".*

"**kV**" means a kilovolt.

"**Laclede**" has the meaning ascribed thereto under "*General Development of the Business - Three Year History and Significant Acquisitions - Recent Developments - 2013 - Liberty Utilities -Acquisition of New England Gas System".*

"**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**" means Liberty Utilities Co. See *"Corporate Structure - Name, Address and Incorporation"*.

"**Liberty Credit Facility**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2012 - Liberty Utilities - Expansion of Liberty Credit Facility".*

"**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 - Production Method, Principal Markets, Distribution Methods and Material Facilities - Power Generation: Renewable - Hydroelectric - Material Facilities - Long Sault Hydro Facility"*.

"**LPSCo System**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Utilities: Water and Waste Water, Material Facilities - LPSCo Water & Waste Water Utility"*.

"**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 "*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 - General Description of the Regulatory Regimes in which the Business Operates - Power Generation Regulatory Regimes - United States - Rate Regulation"*.

"**MDPU**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Liberty Utilities: Electrical Distribution - Material Facilities - Granite State Electric System"*.

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

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

"**Midstates Gas System**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2012 - Liberty Utilities - Acquisition of Midstates Gas System"*.

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

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

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

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

"**Mont-Laurier Hydro Facility**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Power Generation: Renewable - Hydroelectric - Material Facilities - Mont-Laurier Hydro Facility"*.

"**Mont-Laurier Partnership**" means Algonquin Power (Mont-Laurier) Limited Partnership. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**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 *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2011 - APCo - Power Generation - AES Standard Offer Contract".*

"**MPSC**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Liberty Utilities: Electrical Distribution - Material Facilities - Granite State Electric System"*.

"**MW**" means megawatt.

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

"**NB Power**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Power Generation: Renewable - Hydroelectric - Principal Markets and Distribution Methods - New Brunswick and Northern Maine"*.

"**NBSO**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Power Generation: Renewable - Hydroelectric - Principal Markets and Distribution Methods - New Brunswick and Northern Maine".*

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

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

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

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

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

"**Northland**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Power Generation: Thermal - Cogeneration - Material Facilities - Kirkland Thermal Facility".*

"**Northwest Waste Utility**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

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

"**OEB**" means the Ontario Energy Board.

"**OEFC**" means Ontario Electric Financial Corporation.

"**Offering**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2011 - Corporate - Issuance of $95.3 million of Common Shares".*

"**OPA**" means the Ontario Power Authority.

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

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

"**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 - Subsidiaries"*.

"**Peel**" means the Regional Municipality of Peel, Ontario.

"**PGA**" has the meaning ascribed thereto under *"Risk Factors - Financial Risk Management - Commodity Price Risk - Liberty Utilities"*.

"**PG&E**" means Pacific Gas & Electric Company. See *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Power Generation: Thermal - Cogeneration - Material Facilities - Sanger Thermal Facility".*

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

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

"**PJM**" means PJM Interconnection. See *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Power Generation: Renewable - Wind Power - Principal Markets and Distribution Methods - Illinois and Pennsylvania"*.

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

"**Power Pool**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Power Generation: Renewable - Hydroelectric - Principal Markets and Distribution Methods - Alberta".*

"**PPAs**" means long term power purchase agreements. See *"General Development of the Business - General - Business Strategy".*

"**Primary Energy Production Hedge**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Power Generation: Renewable - Wind Power - Material Facilities - Sandy Ridge Wind Facility"*.

"**PSC**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Utilities: Water and Wastewater - Principal Markets - Arkansas".*

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

"**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 - Production Method, Principal Markets, Distribution Methods and Material Facilities - Liberty Utilities: Electrical Distribution - Principal Markets - California".*

"**PTC**" or "**Production Tax Credits**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - APCo: Development Division - Principal Market Environment"*.

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

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

"**Québec AG**" has the meaning ascribed thereto under *"Legal Proceedings and Regulatory Actions - Legal Proceedings - Côte Ste-Catherine Water Lease Dues"*.

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

"**QF Status**" has the meaning ascribed thereto under *"Risk Factors - Regulatory Climate and Permitting Risks - APCo"*.

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

"**REA**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - APCo: Development Division - Current Development Projects - Amherst Island Wind Project"*.

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

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

"**Red Lily Wind Facility**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Power Generation: Renewable - Wind Power - Material Facilities - Red Lily Wind Facility"*.

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

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

"**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 - Production Method, Principal Markets, Distribution Methods and Material Facilities - Utilities: Water and Waste Water - Material Facilities - Rio Rico Water & Wastewater System"*.

"**ROE**" has the meaning ascribed thereto under *"Description of the Business - Production Methods, Principal Markets, Distribution Methods and Material Facilities - Liberty Utilities: Natural Gas Distribution - Material Facilities - Peach State Gas System"*.

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

"**RTOs**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Power Generation: Renewable - Wind Power - Principal Markets and Distribution Methods - Illinois and Pennsylvania"*.

"**S&P**" has the meaning ascribed thereto under "*General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2012 - Corporate - Issuance of $120M of Preferred Shares"*.

"**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 - Power Generation: Thermal - Cogeneration - Material Facilities - Sanger Thermal Facility"*.

"**SaskPower**" means Saskatchewan Power Corporation.

"**Seaway Management**" has the meaning ascribed thereto under *"Risk Factors - Operational Risk Management - Litigation risks and other contingencies"*.

"**Secondary Energy Production Hedge**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Power Generation: Renewable - Wind Power - Material Facilities - Sandy Ridge Wind Facility"*.

"**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 A Shares**" has the meaning ascribed thereto under "*General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2012 - Corporate - Issuance of $120M of Preferred Shares"*.

"**Series D Shares**" has the meaning ascribed thereto under *"General Development of the Business - Recent Developments 2013 - Corporate - Issuance of $100,000,000 of preferred shares"*.

"**Series 1A Debentures**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2011 - Corporate - Conversion of Convertible Debentures to Equity"*.

"**Series 1A Redemption Date**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2011 - Corporate -Conversion of Convertible Debentures to Equity"*.

"**Series 2A Debentures**" has the meaning ascribed thereto under "*General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2012 - Corporate - Conversion of Series 2A Convertible Debentures to Equity"*.

"**Series 2A Redemption Date**" has the meaning ascribed thereto under "*General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2012 - Corporate - Conversion of Series 2A Convertible Debentures to Equity"*.

"**Series 3 Debentures**" has the meaning ascribed thereto under "*General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2012 - Corporate - Conversion and Redemption of Series 3 Convertible Debentures to Equity"*.

"**Series 3 Redemption Date**" has the meaning ascribed thereto under "*General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2012 - Corporate - Conversion and Redemption of Series 3 Convertible Debentures to Equity"*.

"**Shady Oaks Wind Facility**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2013 - APCo - Power Generation - Acquisition of Shady Oaks Wind Facility"*.

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

"**SIR**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Liberty Utilities: Natural Gas Distribution - Principal Markets - Illinois"*.

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

"**SRAF**" has the meaning ascribed thereto under *"General Development of the Business - Fiscal 2013 - Liberty Utilities - Granite State Electric System Rate Proceedings"*.

"**St. Alban Hydro Facility**" means the St. Alban hydroelectric generating facility.

"**St. Brigitte Hydro Facility**" means the St. Brigitte hydroelectric generating facility.

"**Steelworkers**" has the meaning ascribed thereto under *"Risk Factors - 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".*

"**St. Raphael Hydro Facility**" means the St. Raphael hydroelectric generating facility.

"**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 2011 - Corporate - Strategic Investment Agreement with Emera".*

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

"**Tax Partner**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2013 - APCo - Power Generation - Acquisition of the 20 MW ac Bakersfield Solar Project"*.

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

"**TCEQ**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Utilities: Water and Wastewater - Principal Markets - Texas".*

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

"**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 - Production Method, Principal Markets, Distribution Methods and Material Facilities - Power Generation: Renewable - Hydroelectric - Material Facilities - Tinker Hydro Facility"*.

"**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"*.

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

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

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

"**U.S. Wind Portfolio Facilities**" has the meaning ascribed thereto under "Corporate Structure – *Intercorporate Relationships - Subsidiaries - Independent Power Generation Business – APCo Chain - APFA Group".*

"**UDEP**" has the meaning ascribed thereto under "*Description of the Business - Competitive Conditions - APCo - Power Generation*".

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

"**UWUA**" has the meaning ascribed thereto under *"Risk Factors - Labour Relations"*.

"**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 - Production Method, Principal Markets, Distribution Methods and Material Facilities - Power Generation: Renewable - Wind Power - Material Facilities - St. Leon Wind Facility"*.

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

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

"**Windsor LLC**" means Algonquin Power Windsor Locks LLC, a Connecticut limited liability company. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**Windsor Locks Thermal Facility**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Power Generation: Thermal - Cogeneration - Material Facilities - Windsor Locks Thermal Facility"*.

"**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".*

"**WPPI**" has the meaning ascribed thereto under *"Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities - Power Generation: Renewable - Wind Power - Material Facilities - St. Leon Wind Facility".*

Consolidated Financial Statements of
Algonquin Power & Utilities Corp.
For the years ended December 31, 2013 and 2012

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, 2013, based on the framework established in *Internal Control – Integrated Framework (1992)* 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 at December 31, 2013.

During the year ended December 31, 2013, APUC acquired Shady Oaks Holdings, TianRun Shady Oaks LLC, GSG 6 LLC, Liberty Utilities (Pine Bluff Water) Inc., Liberty Utilities (Peach State Natural Gas) Corp. and Liberty Utilities (New England Natural Gas Company) Corp. As of December 31, 2013, these acquired entities represent 16% of total assets and represent 10% and 17% of revenue and earnings from continuing operations before income taxes, respectively, for the year then ended. As permitted by National Instrument 52-109 and the U.S. Securities and Exchange Commission, Management excluded these acquisitions from its evaluation of the effectiveness of the Company's internal controls over financial reporting as of December 31, 2013 due to the complexity associated with assessing internal controls during integration efforts and the proximity of certain of the acquisitions to year-end.

The Company also excluded the 2012 acquisitions of Liberty Utilities (Granite State Electric) Corp., Liberty Utilities (EnergyNorth Natural Gas) Corp., Liberty Utilities (Midstates Natural Gas) Corp. and Wind Portfolio SponsorCo LLC from its evaluation of the effectiveness of APUC's internal controls over financial reporting as of December 31, 2012 due to the complexity associated with assessing internal controls during integration efforts and the proximity of some of the acquisitions to year-end. The 2012 acquisitions were associated with total assets of $1,494.5 million and total revenues of $116.1 million included in the consolidated financial statements of the Company as of and for the year ended December 31, 2012.

March 14, 2014

/s/ Ian Robertson
Chief Executive Officer

/s/ David Bronicheski
Chief Financial Officer

INDEPENDENT AUDITORS' REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM TO SHAREHOLDERS

Report on financial statements

We have audited the accompanying consolidated financial statements of Algonquin Power & Utilities Corp., which comprise the consolidated balance sheet as at December 31, 2013 and the consolidated statements of operations, comprehensive income (loss), equity, and cash flows for the year 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 audit. We conducted our audit 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, 2013, and the consolidated results of its operations and its cash flows for the year ended December 31, 2013, 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, 2013, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) and our report dated March 14, 2014 expressed an unqualified opinion on Algonquin Power & Utilities Corp.'s internal control over financial reporting.

/s/ Ernst & Young LLP

Toronto, Canada

March 14, 2014

Chartered Accountants,

Licensed Public Accountants



A member firm of Ernst & Young Global Limited

INDEPENDENT AUDITORS' REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM TO SHAREHOLDERS

Report on internal controls under standards of the Public Company Accounting Oversight Board (United States)

We have audited Algonquin Power & Utilities Corp.'s internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 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 under the heading Internal controls over financial reporting in Management's Discussion and Analysis for the year ended December 31, 2013. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

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

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

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



As indicated under the heading Internal controls over financial reporting in Management's Discussion and Analysis, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of Shady Oaks Holdings, TianRun Shady Oaks LLC, GSG 6 LLC, Liberty Utilities (Pine Bluff Water) Inc., Liberty Utilities (Peach State Natural Gas) Corp. and Liberty Utilities (New England Natural Gas Company) Corp., which are included in the 2013 consolidated financial statements of Algonquin Power & Utilities Corp. and constituted 16% of total assets, as of December 31, 2013, and 10% and 17% of revenue and earnings from continuing operations before income taxes, respectively, for the year then ended. Our audit of internal control over financial reporting of Algonquin Power & Utilities Corp. also did not include an evaluation of the internal control over financial reporting of Shady Oaks Holdings, TianRun Shady Oaks LLC, GSG 6 LLC, Liberty Utilities (Pine Bluff Water) Inc., Liberty Utilities (Peach State Natural Gas) Corp. and Liberty Utilities (New England Natural Gas Company) Corp.

In our opinion, Algonquin Power & Utilities Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, 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 sheet of Algonquin Power & Utilities Corp. as of December 31, 2013, and the related consolidated statements of comprehensive income (loss), equity, and cash flows for the year ended December 31, 2013 of Algonquin Power & Utilities Corp. and our report dated March 14, 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Chartered Accountants,

Licensed Public Accountants

Toronto, Canada

March 14, 2014



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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders of Algonquin Power & Utilities Corp.

We have audited the accompanying consolidated balance sheet of Algonquin Power & Utilities Corp. as of December 31, 2012, and the related consolidated statements of operations, comprehensive income (loss), equity and cash flows for the year then ended. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

We conducted our audit 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 plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Algonquin Power & Utilities Corp. as of December 31, 2012, and its consolidated results of operations and its consolidated cash flows for the year then ended in conformity with US generally accepted accounting principles.

The consolidated financial statements as at and for the year ended December 31, 2012 have been restated to retrospectively account for a component of the Company that was determined to meet requirements for asset held for sale classification and discontinued operations presentation in the year ended December 31, 2013 as disclosed in note 20 to the consolidated financial statements for the years ended December 31, 2013 and 2012.

/s/ KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada

March 14, 2013 except for the asset held for sale and discontinued operations adjustments to the 2012 comparative amounts discussed in note 20, which is as of March 14, 2014

KPMG LLP, is a Canadian limited liability partnership and a member firm of the KPMG Network of independent member firms affiliated with KPMG International, a Swiss cooperative. KPMG Canada provides services to KPMG LLP.

Algonquin Power & Utilities Corp.
Audited Consolidated Balance Sheets

(thousands of Canadian dollars)

	December 31, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 13,839	$ 53,122
Accounts receivable, net (note 4)	156,712	88,359
Natural gas in storage (note 1(g))	25,609	19,279
Supplies and consumables inventory	7,924	4,233
Regulatory assets (note 7)	34,643	10,644
Due from related parties (note 21)	—	816
Prepaid expenses	11,341	10,861
Notes receivable (note 8)	598	537
Deferred tax asset (note 19)	19,652	10,567
Income tax receivable (note 19)	379	556
Derivative instruments (note 26)	9,176	7,020
Assets held for sale (note 20)	23,927	26,900
	303,800	232,894
Property, plant and equipment (note 5)	2,708,704	2,086,278
Intangible assets (note 6)	54,416	56,781
Assets held for sale (note 20)	—	76,437
Goodwill (note 6)	84,647	61,459
Regulatory assets (note 7)	155,705	123,748
Derivative instruments (note 26)	27,123	6,230
Long-term investments and notes receivable (note 8)	32,746	37,646
Deferred non-current income tax asset (note 19)	86,632	77,497
Other assets (note 13)	18,784	20,020
	$ 3,472,557	$ 2,778,990

Algonquin Power & Utilities Corp.
Audited Consolidated Balance Sheets

(thousands of Canadian dollars)

	December 31, 2013	December 31, 2012
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 14,489	$ 34,271
Accrued liabilities	142,414	95,708
Due to related parties (note 21)	—	1,811
Dividends payable (note 18)	17,535	15,498
Regulatory liabilities (note 7)	21,632	8,626
Long term liabilities (note 9)	8,339	1,768
Pension and other post-employment benefits (note 11)	305	—
Other long term liabilities (note 14)	7,451	4,352
Advances in aid of construction (note 1(o))	1,239	591
Derivative instruments (note 26)	2,492	2,211
Environmental obligations (note 23(a)(ii))	10,111	2,523
Preferred shares series C (note 12)	1,038	—
Liabilities held for sale (note 20)	1,471	1,211
Income tax liability (note 19)	5,159	539
Deferred credits (note 19)	7,778	5,754
Deferred income tax liability (note 19)	2,308	1,133
	243,761	175,996
Long-term liabilities (note 9)	1,247,249	769,058
Convertible debentures (note 10)	—	960
Advances in aid of construction (note 1(o))	77,697	71,626
Regulatory liabilities (note 7)	101,657	82,050
Deferred income tax liability (note 19)	137,153	100,798
Derivative instruments (note 26)	13,729	15,605
Deferred credits (note 19)	17,115	25,816
Pension and other post-employment benefits (note 11)	70,532	59,246
Environmental obligation (note 23(a)(ii))	59,444	54,817
Other long-term liabilities (note 14)	20,492	20,889
Preferred shares series C (note 12)	17,767	—
	1,762,835	1,200,865
Equity:		
Preferred shares (note 15(b))	116,546	116,546
Common shares (note 15(a))	1,351,264	1,245,326
Subscription receipts (note 15(a)(ii))	—	61,160
Additional paid-in capital	7,313	5,224
Deficit	(488,406)	(406,143)
Accumulated other comprehensive loss (note 16)	(31,410)	(104,867)
Total Equity attributable to shareholders of Algonquin Power & Utilities Corp.	955,307	917,246
Noncontrolling interests	510,654	484,883
Total Equity	1,465,961	1,402,129
Commitments and contingencies (note 23)		
Subsequent events (notes 9, 15, 18, 20 and 23)		
	$ 3,472,557	$ 2,778,990

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Audited Consolidated Statements of Operations

(thousands of Canadian dollars, except per share amounts)

	2013	2012
Revenue:		
Regulated electricity sales and distribution	$ 166,156	$ 108,457
Regulated gas sales and distributions	261,672	75,718
Regulated water reclamation and distribution	57,350	46,423
Non-regulated energy sales	180,191	114,351
Other revenue	9,922	3,857
	675,291	348,806
Expenses		
Operating	188,952	117,826
Regulated electricity purchased	97,376	68,209
Regulated gas purchased	148,784	37,461
Non-regulated fuel for generation	17,151	14,589
Depreciation of property, plant and equipment	91,978	45,187
Amortization of intangible assets	4,200	4,151
Administrative expenses	23,518	19,572
Gain on foreign exchange	(567)	(561)
	571,392	306,434
Operating income from continuing operations	103,899	42,372
Interest expense	53,345	35,620
Interest, dividend income and other income	(7,785)	(7,239)
Loss on sale of assets	750	—
Acquisition-related costs	2,140	7,688
Gain on derivative financial instruments (note 26(b)(iv))	(5,200)	(233)
	43,250	35,836
Earnings from continuing operations before income taxes	60,649	6,536
Income tax expense (recovery) (note 19)		
Current	2,526	738
Deferred	6,629	(15,105)
	9,155	(14,367)
Earnings from continuing operations	51,494	20,903
Income/(loss) from discontinued operations net of tax (note 20)	(42,011)	1,043
Net earnings	9,483	21,946
Net earnings/(loss) attributable to noncontrolling interests	(10,813)	7,414
Net earnings attributable to shareholders of Algonquin Power & Utilities Corp.	$ 20,296	$ 14,532
Basic net earnings per share from continuing operations (note 22)	$ 0.28	$ 0.08
Basic net earnings/(loss) per share from discontinued operations (note 22)	(0.21)	0.01
Basic net earnings per share (note 22)	0.07	0.09
Diluted net earnings per share from continuing operations (note 22)	0.28	0.08
Diluted net earnings/(loss) per share from discontinued operations (note 22)	(0.20)	0.01
Diluted net earnings per share (note 22)	$ 0.07	$ 0.09

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Audited Consolidated Statements of Comprehensive Income (Loss)

(thousands of Canadian dollars)				
		2013		**2012**
Net earnings	$	9,483	$	21,946
Other comprehensive income (loss):				
Foreign currency translation adjustment, net of tax of $149 and tax recovery of $388, respectively (notes 1(v), 26(b)(iii) and 26(c))		81,597		(9,399)
Change in fair value of cash flow hedge, net of tax expense of $5,103 and $1,715, respectively (note 26(b)(ii))		17,308		5,168
Change in unrealized pension and other post-retirement expense, net of tax expense of $10,896 and tax recovery of $1,653, respectively (note 11)		16,727		(2,458)
Other comprehensive income (loss), net of tax		115,632		(6,689)
Comprehensive income		125,115		15,257
Comprehensive income attributable to the noncontrolling interests		31,362		9,082
Comprehensive income attributable to shareholders of Algonquin Power & Utilities Corp.	$	93,753	$	6,175

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Audited Consolidated Statement of Equity
(thousands of Canadian dollars)

For the year ended December 31, 2013:								
	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)					—
Exercise of subscription receipts			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				2,089				2,089
Preferred Series C shares					(18,497)			(18,497)
Acquisition of non-controlling interest (notes 3(i) and 21)					(10,302)			(10,302)
Balance, December 31, 2013	$ 1,351,264	$ 116,546	$ —	$ 7,313	$ (488,406)	$ (31,410)	$ 510,654	$ 1,465,961

Algonquin Power & Utilities Corp.
Audited Consolidated Statement of Equity
(thousands of Canadian dollars)

For the year ended December 31, 2012:	Common Shares	Preferred Shares	Subscription Receipts	Additional paid-in capital	Accumulated Deficit	Accumulated OCI	Non-controlling interests	Total
Balance, December 31, 2011	$ 975,263	$ —	$ —	$ 1,525	$ (366,080)	$ (96,510)	$ 38,497	$ 552,695
Net earnings	—	—	—	—	14,532	—	7,414	21,946
Other comprehensive income /(loss)	—	—	—	—	—	(8,357)	1,668	(6,689)
Dividends declared and distributions to non-controlling interests	—	—	—	—	(43,619)	—	(2,640)	(46,259)
Dividends and issuance of shares under dividend reinvestment plan	7,343	—	—	—	(7,343)	—	—	—
Exercise and conversion of subscription receipts	142,609	—	—	—	—	—	—	142,609
Issuance of subscription receipts	—	—	61,160	—	—	—	—	61,160
Conversion and redemption of convertible debentures	118,779	—	—	(689)	—	—	—	118,090
Issuance of common shares under employee share purchase plan	432	—	—	—	—	—	—	432
Stock compensation expense	—	—	—	1,956	—	—	—	1,956
Public offering related taxes	900							900
Issuance of preferred shares	—	116,546	—	—	—	—	—	116,546
Acquisition of 49.99% of Liberty Energy (California)	—	—	—	—	(3,633)	—	(35,023)	(38,656)
Acquisition of U.S. Wind farms	—	—	—	2,432	—	—	474,967	477,399
Balance, December 31, 2012	$ 1,245,326	$ 116,546	$ 61,160	$ 5,224	$ (406,143)	$ (104,867)	$ 484,883	$ 1,402,129

See accompanying notes to consolidated financial statements

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

(thousands of Canadian dollars)

	2013	2012
Cash provided by (used in):		
Operating Activities:		
Net earnings from continuing operations	$ 51,494	$ 20,903
Adjustments and items not affecting cash:		
Depreciation of property, plant and equipment	91,978	45,187
Amortization of intangible assets	4,200	4,151
Other amortization	2,891	2,175
Deferred taxes	6,629	(15,105)
Unrealized gain on derivative financial instruments	(6,758)	(3,127)
Share-based compensation	2,000	1,956
Cost of equity funds used for construction purposes	(1,786)	—
Pension and post retirement expense	(302)	2,852
Loss on sale of long lived assets	750	—
Changes in non-cash operating items (note 24)	(47,819)	(3,476)
Changes in non-cash operating items from discontinued operations (note 24)	36	(408)
Cash provided/(used) in discontinued operations (note 20)	(4,388)	7,846
	98,925	62,954
Financing Activities:		
Cash dividends on common shares	(52,335)	(36,917)
Cash dividends on preferred shares	(5,400)	(769)
Cash distributions to noncontrolling interests	(5,591)	(2,640)
Issuance of common shares	29,983	143,041
Proceeds from subscription receipts	—	61,160
Issuance of preferred shares	—	115,300
Deferred financing costs	(2,240)	(5,435)
Increase in long-term liabilities	950,346	505,542
Decrease in long-term liabilities	(685,472)	(75,432)
Increase in advances in aid of construction	2,299	1,051
Decrease in other long-term liabilities	(1,574)	(860)
	230,016	704,041
Investing Activities:		
Decrease in restricted cash	1,430	805
Increase in other assets	(3,004)	(2,481)
Distributions received in excess of equity income	727	343
Proceeds from sale of discontinued operations	24,968	—
Receipt of principal on notes receivable	109	1,894
Additions to property, plant and equipment	(158,377)	(75,692)
Additions to intangibles	—	(2,237)
Acquisitions of operating entities	(239,014)	(669,905)
Acquisition of noncontrolling interest	—	(38,756)
Proceeds from sale of long lived assets	3,408	204
	(369,753)	(785,825)
Effect of exchange rate differences on cash	1,529	(935)
Decrease in cash and cash equivalents	(39,283)	(19,765)
Cash and cash equivalents, beginning of the period	53,122	72,887
Cash and cash equivalents, end of the period	$ 13,839	$ 53,122

Supplemental disclosure of cash flow information:	2013	2012
Cash paid during the period for interest expense	$ 44,185	$ 28,635
Cash paid during the period for income taxes	$ 1,107	$ 252
Non-cash transactions		
Property, plant and equipment acquisitions in accruals	$ 10,829	$ 10,495

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp. ("APUC" or the "Company") is an incorporated entity under the Canada Business Corporations Act. APUC's principal activity is the ownership of power generation facilities and water, gas and electric utilities, through investments in securities of subsidiaries including corporations, limited partnerships and trusts which carry on these businesses.

APUC's power generation business unit conducts business under the name Algonquin Power Co. ("APCo"). APCo owns or has interests in renewable energy facilities and thermal energy facilities. APUC's Utility Services business unit conducts business under the name of Liberty Utilities Co. ("Liberty Utilities"). Liberty Utilities operates a portfolio of utilities in the United States of America providing electric, natural gas, water distribution or wastewater services.

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. Intercompany transactions and balances have been eliminated.

(c) Accounting for rate regulated operations

The regulated utility operating companies owned by Liberty Utilities 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 ASC Topic 980 Regulated Operations ("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 making process. Included in Note 7, Regulatory Assets & Liabilities 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 income 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 represent 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 13) 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) Gas in storage

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).

(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 (allowance for borrowed funds used during construction) and a return on other funds (allowance for equity funds used during construction). 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. 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.

	2013	2012
Interest capitalized on non-regulated property	$ 669	$ 1,036
AFUDC capitalized on regulated property:		
Allowance for borrowed funds	1,055	628
Allowance for equity funds	1,786	1,108
Total	$ 3,510	$ 2,772

Improvements that increase or prolong the service life or capacity of an asset are capitalized. Maintenance and repair costs are expensed as incurred.

1. Significant accounting policies (continued)

(i) Property, plant and equipment (continued)

Investment tax credits and government grants 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. Contributions in aid of construction represent amounts contributed by customers and governments and developers for 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 range of estimated useful lives and the weighted average useful lives are summarized below:

	Range of useful lives		Weighted average useful lives	
	2013	**2012**	**2013**	**2012**
Generation				
Renewable	3 – 60	3 – 60	35	32
Thermal	3 – 40	3 – 40	24	23
Distribution				
Gas	5 – 80	5 – 80	38	38
Electrical	8 – 75	8 – 75	41	42
Water & wastewater	5 – 50	5 – 50	39	25
Equipment	5 – 50	5 – 50	24	21

In accordance with regulator-approved accounting policies, when depreciable property, plant and equipment of Liberty Utilities 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 operation 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) Intangibles

The fair value of power sales contracts acquired in business combinations are amortized on a straight-line basis over the remaining term of the contract. These periods range from 6 to 25 years from 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.

The Company annually assesses qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit 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, 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 variable interest entities ("VIEs"). To identify potential VIEs, management reviews contracts under leases, long-term purchase power agreements, tolling contracts 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.

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 65% after tax cash flows of the facility from 2014 to 2027 and 58% 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 21). APUC has determined that the facility is a VIE since the Company is the primary beneficiary and therefore 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 $44,319 (2012 - $42,566) and to $37,143 (2012 - $38,136), respectively. The Long Sault debt only has recourse over the Long Sault generating assets. The financial performance of Long Sault reflected on the statement of operations includes non-regulated energy sales of $10,155 (2012 - $8,747), operating expenses and amortization of $2,391 (2012 - $2,728) and interest expense of $3,632 (2012 - $3,929).

(n) Long-term investments and notes receivable

Investments in which APUC has significant influence but are not controlled are accounted using the equity method. APUC records its share in the income or loss of its investees in interest, dividend and other income in the consolidated statements of operations.

Notes receivable are financial assets with fixed or determined payments that are not quoted in an active market. Notes receivable that exceed one year and bear interest at a market rate based on the customer's credit quality are initially recorded at cost, which is generally face value. Subsequent to acquisition, they 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.

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 in other long-term liabilities.

1. Significant accounting policies (continued)

(o) Advances in aid of construction (continued)

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 2013, $627 (2012 - $3,555) 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 Liberty Utilities' 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 credit worthy.

(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 other post employment benefit plans on the consolidated balance sheets. The Company's expense and liabilities are determined by actuarial valuations, using assumptions that are evaluated annually at 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 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.

(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) Stock 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 stock-based compensation as a cost in the 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.

1. Significant accounting policies (continued)

(t) Noncontrolling interests

Noncontrolling interest represents the portion of equity ownership in subsidiaries that is not attributable to the equity holders of the parent Company. Noncontrolling interests are initially recorded at fair value and subsequently the amount is adjusted for the proportionate share of earnings and other comprehensive income attributable to the noncontrolling interests and any dividends or distributions paid to the noncontrolling interests.

Noncontrolling interest represents the portion of equity ownership in subsidiaries that is not attributable to the equity holders of the parent Company. Noncontrolling interests are initially recorded at fair value and subsequently the amount is adjusted for the proportionate share of earnings and other comprehensive income attributable to the noncontrolling interests and any dividends or distributions paid to the noncontrolling interests.

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

Certain of the Company's U.S. based wind businesses are organized as limited liability corporations and partnerships and have noncontrolling 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 noncontrolling interest holders in these subsidiaries is calculated using the Hypothetical Liquidation at Book Value ("HLBV") method of accounting. HLBV uses a balance sheet approach, which measures the allocation of income or loss of the Class A's membership 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 17).

(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 sales and revenues 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.

Beginning in 2013, in accordance with the revenue decoupling mechanism approved by its regulator, Liberty Utilities (CalPeco Electric) LLC ("Calpeco Electric System ") is required to charge approved annual delivery revenues evenly over its 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).

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 waste water 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.

Revenue is recorded net of sale taxes.

Interest from long-term investments is recorded as earned.

1. Significant accounting policies (continued)

(v) Foreign currency translation

The Company's reporting currency is the Canadian dollar.

The Company's US 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 while revenues and expenses are converted 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 other comprehensive income ("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.

(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 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. They 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 follows ASC 740-10 and 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, convertible debentures, 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 for items classified as held-for-trading are expensed immediately. Transaction costs that are directly attributable to the issuance of financial liabilities, costs of arranging the Company's credit facility 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 revolving credit facilities are amortized on a straight-line basis over the term of the 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 sheet. 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.

1. Significant accounting policies (continued)

(x) Financial instruments and derivatives (continued)

For derivatives designated in a cash flow hedge relationship, the effective portion of the change in fair value is recognized as other comprehensive income. The ineffective portion is immediately recognized in earnings. The amount recognized in accumulated other comprehensive income is removed and included in earnings in the same period as the hedged cash flows affect earnings under the same line item in the statement of income 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 accumulated other comprehensive income is transferred to the income statement in the same period that the hedged item affects profit or loss. If the forecast transaction is no longer expected to occur, then the balance in accumulated other comprehensive income is recognized immediately in earnings.

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

Calpeco Electric System and Liberty Utilities (Granite State Electric) Corp. ("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 on-going 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.

1. Significant accounting policies (continued)

(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 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 and intangible assets, the annual impairment testing of reporting units containing 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, and the fair value of financial instruments, derivatives and share-based compensation. 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 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities and ASU 2013-01 Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities. These newly issued accounting standards require an entity to disclose both gross and net information about financial instruments and transactions eligible for offset in the balance sheet including financial instruments and transactions executed under a master netting or similar arrangement. The standards were issued to enable users of the financial statements to understand the effects or potential effects of such arrangements on an entity's financial position. The adoption of these standards as at January 1, 2013 did not have a material impact on the Company's consolidated financial statements.

The FASB issued ASU 2013-02, Comprehensive Income (Topic 220): This newly issued accounting standard requires an entity to provide certain information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes to the financial statements, the effect of, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under U.S. GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under U.S. GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under U.S. GAAP that provide additional detail about those amounts. Other than the additional disclosure (note 16), the adoption of this standard did not have a material impact on the Company's consolidated financial statements.

2. Recently issued accounting pronouncements (continued)

(b) Recent accounting guidance not yet adopted

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 tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward, except in some specific situations. This ASU is required to be applied prospectively for fiscal years, and interim periods beginning after December 15, 2013. The adoption of this standard is not expected to have an impact 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 permit 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. This ASU is required to be applied prospectively for qualifying new or re-designated hedging relationships entered into on or after July 17, 2013. 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 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 provide 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. This ASU is required to be applied retrospectively for fiscal years, and interim periods within those years beginning after December 15, 2013. 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) Agreement to acquire the noncontrolling interest in U.S. Wind farms

On November 28, 2013, APCo entered into an agreement to acquire the 40% interest in Wind Portfolio SponsorCo, LLC ("SponsorCo") from Gamesa Corporación Tecnológica, S.A. for approximately U.S. $117,000. SponsorCo indirectly holds the interests in Sandy Ridge, Senate and Minonk Wind acquired in 2012. The transaction will result in the elimination of the noncontrolling interest in respect of the Class B partnership units of SponsorCo including its portion of Accumulated other comprehensive income and resulting tax effect. Any difference with the consideration paid will be recorded as Additional paid-in capital.

3. Business acquisitions and development projects (continued)

(b) Acquisition of New England Gas System

On December 20, 2013, Liberty Utilities 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 approximately U.S. $59,100, subject to certain working capital and other closing adjustments.

The following table summarizes the preliminary determination of the fair value of the assets acquired and liabilities assumed at the acquisition date:

Cash	$	76
Working capital		8,175
Property, plant and equipment		84,636
Regulatory assets		47,644
Other assets		1,197
Long term debt (including current portion)		(25,836)
Regulatory liabilities		(15,969)
Pension and OPEB		(25,360)
Environmental obligation		(10,225)
Deferred income tax liability, net		(1,217)
Total net assets acquired	$	63,121

Due to the timing of the acquisition, the Company has not completed the fair value measurements of the assets acquired and liabilities assumed. The determination of the fair value has been based upon management's preliminary estimates of final closing adjustments, certain estimates and assumptions with respect to the fair values of the assets acquired and liabilities assumed. The Company will continue to review information and perform further analysis prior to finalizing the fair value of the consideration paid and the fair value of the assets acquired and liabilities assumed. The actual fair values of the assets acquired and liabilities assumed may differ from the amounts above.

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 New England Gas System assets is 55 years.

All costs related to the acquisition have been expensed through the consolidated statements of operations.

New England Gas System contributed revenue of $3,582 and net earnings of $1,153 to the Company's consolidated financial results for 2013. Pro forma financial information is disclosed in note 3(f).

3. Business acquisitions and development projects (continued)

(c) Acquisition of Peach State Gas System

On April 1, 2013 Liberty Utilities acquired certain regulated natural gas distribution utility assets (the "Peach State Gas System") located in the State of Georgia. The total purchase price for the Peach State Gas System adjusted for certain working capital and other closing adjustments, is approximately $155,578 (U.S. $153,000).

The following table summarizes the preliminary determination of the fair value of the assets acquired and liabilities assumed at the acquisition date:

Working capital	$	9,605
Property, plant and equipment		141,983
Goodwill		12,226
Deferred income tax asset, net		1,992
Derivative asset		231
Regulatory liabilities		(3,807)
Other liabilities		(1,853)
Pension and OPEB		(4,615)
Derivative liabilities		(184)
Total net assets acquired	$	155,578

The Company has not completed the fair value measurement of the assets acquired and liabilities assumed, particularly that of certain executory contracts. The determination of the fair value has been based upon management's preliminary estimates and assumptions with respect to the fair values of the assets acquired and liabilities assumed. The Company will continue to review information and perform further analysis prior to finalizing the fair value of the consideration paid and the fair value of the assets acquired and liabilities assumed. The actual fair values of the assets acquired and liabilities assumed may differ from the amounts above.

Goodwill represents the excess of the fair value of the consideration paid over the fair value of net assets acquired. The contributing factors to the amount recorded as goodwill include expected future cash flows, potential operational synergies, the utilization of technology, and cost savings opportunities in the delivery of certain shared administrative and other services. The goodwill related to the Peach State Gas System has been reported under the Liberty Utilities (East) segment.

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 Peach State Gas System assets is 55 years.

All costs related to the acquisition have been expensed through the consolidated statements of operations.

Peach State Gas System contributed revenue of $37,889 and net earnings of $5,692 to the Company's consolidated financial results for 2013. Pro forma financial information is disclosed in note 3(f).

3. Business acquisitions and development projects (continued)

(d) Acquisition of Pine Bluff Water System

On February 1, 2013, Liberty Utilities acquired United Water Arkansas Inc. a regulated water distribution utility (the "Pine Bluff Water System") located in Pine Bluff, Arkansas. Total purchase price for the Pine Bluff Water System, adjusted for certain working capital and other closing adjustments, is approximately $27,858 (U.S. $27,934).

The following table summarizes the allocation of the assets acquired and liabilities assumed at the acquisition date. The determination of the fair value of assets and liabilities acquired is based upon management's estimates and certain assumptions with respect to the fair values of the assets acquired and liabilities assumed.

Cash	$	8
Working capital		766
Property, plant and equipment		28,371
Regulatory assets		957
Goodwill		5,034
Other liabilities		(169)
Regulatory liabilities		(135)
Pension and OPEB		(4,277)
Deferred income tax liability, net		(2,697)
Total net assets acquired	$	27,858

Goodwill represents the excess of the fair value of the consideration paid over the fair value of net assets acquired. The contributing factors to the amount recorded as goodwill include expected future cash flows, potential operational synergies, the utilization of technology, and cost savings opportunities in the delivery of certain shared administrative and other services. The goodwill related to the Pine Bluff Water System has been reported under the Liberty Utilities (Central) segment.

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 Pine Bluff Water System assets is 40 years.

All costs related to the acquisition have been expensed through the consolidated statements of operations.

Pine Bluff Water System contributed revenue of $8,708 and net earnings of $1,894 to the Company's consolidated financial results for 2013. The disclosure of pro forma revenue and earnings has been deemed immaterial.

3. Business acquisitions and development projects (continued)

(e) Acquisition of Shady Oaks Wind Facility

Effective January 1, 2013, APCo acquired the 109.5 megawatt ("MW") Shady Oaks wind powered generating facility ("Shady Oaks Wind Facility") by assuming the existing long-term debt of approximately U.S. $150,000 for no additional cash. 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.

The following table summarizes the allocation of the assets acquired and liabilities assumed at the acquisition date. The determination of the fair value is based upon management's estimates and assumptions with respect to the fair value of the assets acquired and liabilities assumed.

Cash	$	4,682
Working capital		(846)
Property, plant and equipment		144,243
Deferred tax asset		2,519
Long term debt (including current portion)		(149,235)
Asset retirement obligation		(1,363)
Total net assets acquired	$	—

Property, plant and equipment are amortized on a straight line basis over the lives of the assets, which have a weighted average useful life of 37 years.

Shady Oaks Wind Facility earns revenue from the sale of electricity and renewable energy credits and from capacity payments. Shady Oaks Wind Facility recognizes revenue from the sale of electricity and renewable energy credits ("RECs") based upon the output delivered at rates specified under a long-term power purchase agreement with Commonwealth Edison Company ("ComEd"). Shady Oaks Wind Facility has contracted to sell approximately 310,000 MW hours of electricity (and associated RECs) to ComEd each year, commencing June 1, 2012, under this long-term power purchase agreement. On March 29, 2013, ComEd issued curtailment notice reducing the annual contract quantity for the delivery year from June 1, 2013 to May 31, 2014 to 252,617 MW hours. Electricity and associated renewable energy credits not sold to ComEd will be sold into wholesale electric markets.

Shady Oaks Wind Facility contributed revenue of $17,472 and net earnings of $3,297 to APUC's consolidated financial results for 2013. The disclosure of pro forma revenue and earnings has been deemed impracticable as Shady Oaks Wind Facility being a newly constructed wind power generation facility only achieved commercial operations in the second half of 2012 and therefore had little operations prior to the acquisition by APCo.

All costs related to the acquisition have been expensed in the consolidated statements of operations.

3. Business acquisitions and development projects (continued)

(f) Pro forma information

The supplemental pro forma financial information below was prepared using the acquisition method of accounting and is based on the historical financial information of APUC, New England Gas System and Peach State Gas System reflecting results of operations for 2013 and 2012 on a comparative basis as though the aforementioned companies were combined as of January 1, 2012. The acquiree's pre-acquisition results have been added to APUC's historical results, and the totals have been adjusted for the pro forma effects of acquisition-related costs, interest expense related to the financing of the business combinations, and related income taxes.

Pro forma	**2013**	**2012**
Total revenue from continuing operations	$ 760,394	$ 464,182
Net earnings from continuing operations	59,698	28,103
Basic net earnings from continuing operations per share	0.32	0.13
Diluted net earnings from continuing operations per share	0.32	0.13

The above unaudited pro forma financial information is presented for informational purposes only and does not purport to represent what the results would have been had the acquisition closed on the date assumed, nor is it necessarily indicative of the results that may be expected in future periods.

(g) Acquisition of New Hampshire Electric and Gas Systems

In 2013, the Company received additional information which was used to refine the estimates for fair value of assets acquired and liabilities assumed on July 3, 2012 for the New Hampshire electric and gas utilities. The carrying value of those assets and liabilities were retrospectively adjusted to the amounts detailed in the table below. As a result, the total consideration was reduced by $9,216, working capital acquired was reduced by $9,869 and goodwill was increased by $957.

	Granite State	**EnergyNorth**	**Total**
Cash	$ 395	$ —	$ 395
Restricted cash	3,252	—	3,252
Working capital	1,916	15,420	17,336
Property, plant and equipment	86,935	256,305	343,240
Regulatory assets	31,683	87,126	118,809
Deferred financing	31	—	31
Other assets	—	83	83
Goodwill	—	28,537	28,537
Customer deposits	(661)	(962)	(1,623)
Long-term debt	(15,188)	—	(15,188)
Other long-term liabilities	(1,468)	(3,287)	(4,755)
Advances in aid of construction	—	(86)	(86)
Derivative liabilities	—	(2,598)	(2,598)
Regulatory liabilities	(5,533)	(27,456)	(32,989)
Pension and OPEB	(19,108)	(29,197)	(48,305)
Environmental obligation	—	(54,431)	(54,431)
Deferred income tax liabilities, net	—	(61,484)	(61,484)
Total net assets acquired	$ 82,254	$ 207,970	$ 290,224

3. Business acquisitions and development projects (continued)

(h) Acquisition of solar energy project

On January 4, 2012, APCo acquired rights to develop a 10 MWac solar project located near Cornwall, Ontario which has been granted a Feed-in-Tariff contract by the Ontario Power Authority for a 20 year term at a rate of $443/MWh. The consideration for the development rights is $4,500 plus additional contingent consideration of $3,500 based on achieving certain construction milestones. As at December 31, 2013, the Company has paid a total of $3,000 based on achieved milestones. The transaction has been recorded as a purchase of intangible assets. In addition, as at December 31, 2013, the Company has invested $33,259 in the development and construction of the solar energy project which is recorded as property, plant and equipment.

(i) Acquisition of noncontrolling interest in Calpeco Electric System

On December 21, 2012, APUC acquired the 49.999% interest in Calpeco Electric System from Emera Inc.("Emera") that it did not previously hold for $38,756 which was funded by the proceeds of common share subscription receipts (note 15(a)(ii)). The impact on the Company's consolidated balance sheet was as follows:

		2012
Elimination of noncontrolling interest (net of intercompany balance of $1,297 with Emera)	$	33,726
Noncontrolling interest portion of currency translation adjustment transferred to AOCI		1,397
Accumulated deficit		3,633
Exercise of subscription receipts	$	38,756

During the third quarter of 2013, the Company completed the tax filings in connection with the acquisition of Emera's noncontrolling interest in Calpeco Electric System and identified an adjustment to the deferred tax balance. The $3,649 deferred tax adjustment identified has been recorded in the current period as an adjustment to accumulated deficit consistent with the accounting for the acquisition of the noncontrolling interest.

4. Accounts receivable

Accounts receivable as of December 31, 2013 includes unbilled revenue of $45,274 (December 31, 2012 - $22,658) from the Company's regulated utilities. Accounts receivable as at December 31, 2013 is presented net of allowance for doubtful accounts of $8,461 (December 31, 2012 - $4,360).

5. Property, plant and equipment

Property, plant and equipment consist of the following:

2013	Cost	Accumulated depreciation	Net book value
Generation			
Renewable	$ 1,438,229	$ 166,175	$ 1,272,054
Thermal	116,975	43,596	73,379
Distribution			
Water & wastewater	303,410	63,807	239,603
Electricity	277,679	16,782	260,897
Gas	690,034	19,758	670,276
Land	8,266	—	8,266
Equipment	71,292	25,111	46,181
Construction in progress	138,048	—	138,048
	$ 3,043,933	$ 335,229	$ 2,708,704

2012	Cost	Accumulated depreciation	Net book value
Generation			
Renewable	$ 1,132,631	$ 78,772	$ 1,053,859
Thermal	208,183	78,336	129,847
Distribution			
Water & wastewater	240,376	52,162	188,214
Electricity	259,461	7,765	251,696
Gas	352,491	5,940	346,551
Land	7,318	—	7,318
Equipment	67,740	22,712	45,028
Construction in progress	63,765	—	63,765
	$ 2,331,965	$ 245,687	$ 2,086,278

Renewable generation assets include cost of $86,774 (2012 - $88,198) and accumulated depreciation of $31,739 (2012 - $29,584) related to facilities under capital lease or owned by consolidated variable interest entities. Depreciation expense of facilities under capital lease was $2,155 (2012 - $2,244).

Investments tax credits, government grants and contributions received in aid of construction of $3,098 (2012 - $6,341) 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.

Subsequent to year-end, on January 3, 2014, APUC, through wholly owned subsidiaries, acquired a new office facility in Oakville, Ontario. The purchase price for the building was $46,800 and was financed through APUC's credit facility.

6. Intangible assets and goodwill

Intangible assets consist of the following:

	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

	2012		
	Cost	Accumulated amortization	Net book value
Power sales contracts	$ 60,435	$ 24,881	$ 35,554
Customer relationships	26,674	5,447	21,227
	$ 87,109	$ 30,328	$ 56,781

Estimated amortization expense for intangibles for the next three years is $4,560 each year, $2,810 in year four and $2,470 in year five.

Changes in goodwill per operating segment are as follows:

	Liberty Utilities			
	Central	West	East	Total
Balance, January 1, 2012	$ 192	$ 9,517	$ —	$ 9,709
Business acquisitions	25,257	—	26,527	51,784
Foreign exchange	(357)	(251)	574	(34)
Balance, December 31, 2012	$ 25,092	$ 9,266	$ 27,101	$ 61,459
Business acquisitions	5,034	—	12,226	17,260
Adjustments	(209)	—	957	748
Foreign exchange	2,056	640	2,484	5,180
Balance, December 31, 2013	$ 31,973	$ 9,906	$ 42,768	$ 84,647

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 U.S. Financial Accounting Standards Board ASC Topic 980 Regulated Operations ("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.

On November 29, 2012, the Company's Calpeco Electric System regulator approved an All Parties General Rate Case Settlement. As an element of the decision, a revenue decoupling mechanism and a vegetation management memorandum account were agreed upon. The revenue decoupling mechanism will isolate 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 to customers, one of the largest expenses of the utility.

7. Regulatory matters (continued)

At any given time, Liberty Utilities can have several regulatory proceedings underway. The financial effects of these proceedings are reflected in the financial statements based on regulatory approval obtained to the extent that there is a financial impact during the applicable reporting period.

Regulatory assets and liabilities consist of the following:

	2013	2012
Regulatory assets		
Environmental costs (a)	$ 80,438	$ 59,789
Pension and post-employment benefits (b)	64,997	47,838
Storm costs (c)	5,437	6,726
Energy costs adjustment (d)	20,495	7,962
Rate case costs (e)	3,119	2,398
Vegetation management	2,297	2,082

Debt premium (f)		4,504		—
Asset retirement obligation (g)		1,468		1,095
Tax related		2,995		1,160
Other		4,598		5,342
Total regulatory assets	$	190,348	$	134,392
Less current regulatory assets		(34,643)		(10,644)
Non-current regulatory assets	$	155,705	$	123,748

Regulatory liabilities				
Cost of removal (h)	$	68,698	$	58,852
Rate-base offset (i)		25,082		15,541
Energy costs adjustment (d)		17,394		13,891
Pension and post-employment benefits (b)		6,770		1,127
Rate adjustment mechanism		1,681		—
Tax related		133		—
Other		3,531		1,265
Total regulatory liabilities	$	123,289	$	90,676
Less current regulatory liabilities		(21,632)		(8,626)
Non-current regulatory liabilities	$	101,657	$	82,050

(a) Environmental remediation costs recovery: Actual expenditures incurred for the cleanup of certain former gas manufacturing facilities (see note 23 (a) (ii)) are recovered through rates over a period of 7 years.

(b) Pension and post-employment benefits: As part of a business acquisition, the Regulators authorized a regulatory asset or liability being set up for the amounts of pension and post-retirement benefits that have not yet been recognized in net periodic cost and were presented as accumulated comprehensive income prior to the acquisition. A net portion of $12,213 is currently recovered through rates over the future services years of the employees. The balance of $46,014 relates to recent acquisitions and was authorized for recognition as an asset by the Regulator. Recovery of $23,013 through rates is expected to start in the second quarter of 2014. The remaining $23,001 is anticipated to be approved in a final rate order in 2015.

(c) Storm costs: Incurred repair costs resulting from certain storms, which are expected to be recovered through rates.

7. Regulatory matters (continued)

(d) Energy cost adjustment: The revenue of the electric and natural gas utilities include 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 balance sheet. These differences are reflected in adjustments to rates and recorded as an adjustment to cost of natural gas or electricity in future time 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 are recoverable through the energy cost adjustment (note 26(b)(i)).

(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 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.

(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 Regulator 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.

The Company records carrying charges on the regulatory balances related to energy costs adjustment and storm costs. 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 income in the period of such determination.

8. Long-term investments and notes receivable

Long-term investments and notes receivable consist of the following:

	2013	2012
Long-term investments		
32.4% of Class B non-voting shares of Kirkland Lake Power Corp.	$ 4,851	$ 4,926
25% of Class B non-voting shares of Cochrane Power Corporation	3,772	4,669
45% interest in the Algonquin Power (Rattle Brook) Partnership (b)	—	3,884
50% interest in the Valley Power Partnership	1,718	1,767
Other	325	180
Total long-term investments	$ 10,666	$ 15,426
Notes Receivable		
Red Lily Senior loan, interest at 6.31% (a)	$ 11,588	$ 11,588
Red Lily Subordinated loan, interest at 12.5% (a)	6,565	6,565
Chapais Énergie, Société en Commandite interest at 10.789% and 4.91%, respectively	1,928	2,448
Silverleaf resorts loan, interest at 15.48% maturing July 2020	2,149	2,010
Other	448	146
	22,678	22,757
Less: current portion	(598)	(537)
Total long-term notes receivable	$ 22,080	$ 22,220
Total long-term investments and notes receivable	$ 32,746	$ 37,646

8. Long-term investments and notes receivable (continued)

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

(a) Red Lily I

The Red Lily I Partnership ("Partnership") is owned by an independent investor. The Company provides operation and supervision services to the Red Lily I project, a 26.4 megawatt wind energy facility located in south-eastern 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. In 2011, APUC advanced $13,000 under a senior debt facility to the Partnership and received a pre-payment of $1,412 in 2012. Another third party lender has also advanced $31,000 of senior debt to the Partnership. The Company's senior loan to the Partnership earns interest at the rate of 6.31% and will mature in 2016. 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%, 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 APUC'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 at December 31, 2013 and 2012 was determined to be negligible.

(b) Algonquin Power (Rattle Brook) Partnership

The Algonquin Power (Rattle Brook) Partnership was sold to related parties effective December 31, 2013 (see note 21).

9. Long-term liabilities

Long term liabilities consist of the following:

	2013	2012
APCo		
Revolving $200,000 credit facility, revolving line of credit 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 1.75%, maturing November 16, 2015.	$ 124,570	$ 27,074
Senior Unsecured Notes: $150,000 senior unsecured notes, bearing an interest rate of 4.82% maturing February 15, 2021. The notes are interest only, payable semi-annually in arrears.	149,920	149,910
Senior Unsecured Notes: $135,000 senior unsecured notes, bearing an interest rate of 5.50% maturing July 25, 2018. The notes are interest only, payable semi-annually in arrears.	134,837	134,807
Senior Debt - Shady Oaks Wind Facility: U.S. $122,000 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.	129,759	—
Senior Debt - Long Sault Hydro Facility: Bonds bearing an interest rate of 10.21% maturing December 31,2027. The bonds have interest and principal payments, monthly in arrears.	37,143	38,136

	2013	2012
Senior Debt - Sanger Thermal Facility: 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, maturing September 15, 2020. The bond has interest only payments, payable monthly in arrears. The effective interest rate in 2013 was 1.72% (2012 – 2.29%).	20,421	19,102
Senior Debt - Chuteford Hydro Facility: Bonds bearing an interest rate of 11.6%, maturing April 1, 2020. The bond has principal and interest payments, payable monthly in arrears.	3,417	3,763
Liberty Utilities		
Revolving U.S. $200,000 credit facility, revolving line of credit 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.	85,620	27,360
Senior Unsecured Notes:		
Liberty Utilities Co.: U.S. $50,000, bearing an interest rate of 3.51%, maturing July 31, 2017; U.S. $115,000, bearing an interest rate of 4.49%, maturing August 1, 2022; U.S. $60,000, bearing an interest rate of 4.89%, maturing July 30, 2027; U.S. $15,000, bearing an interest rate of 4.14%, maturing March 13, 2023; 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 notes interest only payments, payable semi-annually.	388,214	223,852
Calpeco Electric System: U.S. $45,000 senior unsecured notes bearing an interest rate of 5.19%, maturing December 29, 2020 and U.S. $25,000 senior unsecured notes bearing an interest rate of 5.59%, maturing December 29, 2025. The notes are interest only payments, payable semi-annually in arrears.	74,452	69,643
Liberty Water Co: U.S. $50,000 senior unsecured notes bearing an interest rate of 5.60% maturing December 22, 2020. The note has interest only payments, payable semi-annually in arrears, until June 20, 2016 after which the note will bear semi-annual interest payments thereafter.	53,180	49,745
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 bonds have interest only payments.	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.	15,954	14,924
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.	11,668	11,269
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.	1,189	1,241
	$ 1,255,588	$ 770,826
Less: current portion	(8,339)	(1,768)
	$ 1,247,249	$ 769,058

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 APUC, APCo or Liberty Utilities. The loans have certain financial covenants, which must be maintained on a quarterly basis. Noncompliance with the covenants could restrict cash distributions/dividends to APUC, APCo and Liberty Utilities from the specific facilities.

APCo

Subsequent to year-end on January 17, 2014, APCo 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 will be payable on February 15 and August 15 each year, commencing on February 15, 2014. APCo incurred deferred financing costs of $940, which are being amortized to interest expense over the term of the loan using the effective interest rate method. Concurrent with the offering, APCo entered into a cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated offering into U.S. dollars. APCo designated the entire notional amount of the cross currency fixed for fixed interest rate swap and related short-term USD payables created by the monthly accruals of the swap settlement as a hedge of the foreign currency exposure of its net investment in APCo'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 USD accruals that are designated as, and are effective as, an economic hedge of the net investment in a foreign operation will be reported in the same manner as the translation adjustment (in other comprehensive income) related to the net investment.

Effective January 1, 2013, concurrent with the acquisition of Shady Oaks Wind Facility (note 3(e)), APCo assumed existing long-term debt of approximately U.S. $150,000. Principal of U.S. $28,000 was repaid during the year and another portion of U.S. $40,000 was paid subsequent to year-end on February 10, 2014 leaving a balance of U.S. $82,000 outstanding at that date. The semi-annual principal repayment schedule for the following 12.5 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 at any time without penalty.

On December 3, 2012, APCo issued $150,000 senior unsecured debentures bearing interest at 4.82% and with a maturity date of February 15, 2021. The debentures were sold at a price of $99.94 per $100.00 principal amount. Interest payments are payable on February 15 and August 15 each year. APCo incurred deferred financing costs of $1,057, which are being amortized to interest expense over the term of the loan using the effective interest rate method. Concurrent with the offering, APCo entered into a cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated offering into U.S. dollars (note 26(b)(iii)).

In 2012, APCo increased the maximum availability under its senior credit facility from $120,000 to $200,000 to meet future working capital needs. In addition, the bank syndicate agreed to release its security previously held over certain APCo entities, such that the facility is now fully unsecured. The facility has a maturity date of November 16, 2015.

Liberty Utilities

On December 20, 2013, in connection with the acquisition of New England Gas System, Liberty Utilities 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 Feb 15, 2020.

On September 30, 2013, Liberty Utilities increased the maximum availability under its revolving credit facility from U.S. $100,000 to $200,000 to meet future working capital requirements and allow for greater financial flexibility. The facility has a maturity date of September 30, 2018.

On July 31, 2013, Liberty Utilities 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 (note 3(c)).

On March 14, 2013 Liberty Utilities issued U.S. $15,000 of senior unsecured notes through a private placement in connection with the acquisition of the Pine Bluff Water System (note 3(d)). The notes bear interest at 4.14% and mature March 13, 2023.

9. Long-term liabilities (continued)

Liberty Utilities (continued)

In July 2012, Liberty Utilities issued U.S. $225,000 of senior unsecured notes through a private placement in three tranches: U.S. $50,000, bearing an interest rate of 3.51%, maturing July 31, 2017; U.S. $115,000, bearing an interest rate of 4.49%, maturing August 1, 2022; and, U.S. $60,000, bearing an interest rate of 4.89%, maturing July 30, 2027. The notes are interest only, payable semi-annually. Liberty Utilities incurred deferred financing costs of $2,663, which are being amortized to interest expense over the term of the loan using the effective interest rate method. Liberty Utilities used the proceeds of the private placement financing to fund a portion of the acquisition of the New Hampshire Electric and Gas Systems and Midwest Gas System.

On July 3, 2012, in connection with the acquisition of Granite State Electric System, Liberty Utilities assumed senior unsecured long-term notes of 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.

APUC

On November 19, 2013, APUC increased the maximum availability under its revolving credit facility from U.S. $30,000 to $65,000. The credit facility will be used for general corporate purposes and has a maturity date of November 19, 2016. As at December 31, 2013 and 2012, no amounts were outstanding under this facility.

As of December 31, 2013, the Company had accrued $14,057 in interest expense (2012 - $4,482). Interest paid on the long-term liabilities in 2013 was $49,746 (2012 - $20,671).

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

	2014	2015	2016	2017	2018	Thereafter	Total
APCo	$ 7,864	$ 132,508	$ 8,212	$ 10,540	$ 10,767	$ 430,176	$ 600,067
Liberty Utilities	475	504	5,852	59,075	91,524	498,091	655,521
Total	$ 8,339	$ 133,012	$ 14,064	$ 69,615	$ 102,291	$ 928,267	$ 1,255,588

10. Convertible debentures

	Series 2A	Series 3	Total
Maturity date	2016 November 30	2017 September 30	
Interest rate	6.35%	7.00%	
Conversion price per share	$ 6.00	$ 4.20	
Carrying value at January 1, 2012	$ 59,726	$ 62,571	$ 122,297
Conversion to common shares (note 15(a)(i)), net of costs	(59,950)	(61,611)	(121,561)
Amortization and accretion	224	—	224
Carrying amount at December 31, 2012	$ —	$ 960	$ 960
Conversion to common shares (note 15(a)(i)), net of costs	—	(960)	(960)
Amortization and accretion	—	—	—
Carrying and fair value amount at December 31, 2013	$ —	$ —	$ —

11. Pension and other post-employment benefits

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. Liberty Utilities 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 Company's policy is to make pension contributions within the range determined by generally accepted actuarial principles. 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.

The Company acquired the Pine Bluff Water System, the Peach State Gas System and New England Gas System in 2013; therefore, the pension and OPEB implications for those current acquisitions are not included in the December 31, 2012 comparative information.

(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 at December 31:

	Pension benefits		OPEB	
	2013	2012	2013	2012
Change in projected benefit obligation				
Projected benefit obligation, at beginning of year	$ 104,291	$ 239	$ 31,674	$ —
Projected benefit obligation assumed from business combination	73,601	101,840	17,943	30,637
Modifications to pension plan	81			—
Service cost	3,273	1,288	1,602	803
Interest cost	4,350	1,906	1,508	606
Actuarial (gain)/loss	(11,395)	2,736	(8,499)	857
Benefits paid	(3,597)	(1,507)	(1,158)	(601)
Loss/(gain) on foreign exchange	7,509	(2,211)	2,329	(628)
Projected benefit obligation at end of year	$ 178,113	$ 104,291	$ 45,399	$ 31,674
Change in plan asset				
Fair value of plan assets at beginning of year	66,524	203	10,195	—
Plan assets acquired in business combination	57,285	68,045	658	10,786
Actual return on plan assets	10,733	1,223	1,730	—
Employer contributions	3,013	—	1,208	231
Benefits paid	(3,597)	(1,507)	(1,158)	(601)
Loss/(gain) on foreign exchange	5,322	(1,440)	762	(221)
Fair value of plan assets at end of year	$ 139,280	$ 66,524	$ 13,395	$ 10,195
Unfunded status	$ (38,833)	$ (37,767)	$ (32,004)	$ (21,479)
Amounts recognized in the consolidated balance sheets consists of:				
Current liabilities	(305)	—	—	—
Non-current liabilities	(38,528)	(37,767)	(32,004)	(21,479)
Net amount recognized	$ (38,833)	$ (37,767)	$ (32,004)	$ (21,479)

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

(b) Net pension and OPEB obligation (continued)

The accumulated benefit obligation for the pension plans was $162,179 and $97,687 at December 31, 2013 and 2012, respectively.

The amounts recognized in accumulated other comprehensive loss before tax were as follows:

	Accumulated other comprehensive income	
	Pension	OPEB
Balance, January 1, 2012	$ 53	$ —
Current year net actuarial gain	3,298	857
Amortization of net actuarial loss	(2)	(32)
Foreign exchange	(16)	(4)
Balance at December 31, 2012	$ 3,333	$ 821
Current year net actuarial loss	(18,011)	(9,644)
Current year prior service loss	82	—
Amortization of net actuarial loss	(23)	(26)
Foreign exchange	234	(234)
Balance at December 31, 2013	$ (14,385)	$ (9,083)

(c) Assumptions

Weighted average assumptions used to determine net benefit cost for 2013 and 2012 were as follows:

	Pension benefits		OPEB	
	2013	2012	2013	2012
Discount rate	3.68%	3.89%	3.69%	3.97%
Expected return on assets	5.51%	5.50%	5.18%	4.66%
Rate of compensation increase	3.13%	3.31%	2.97%	N/A
Healthcare cost trend rate				
Before Age 65			7.68%	8.48%
Age 65 and after			7.68%	7.50%
Assumed Ultimate Medical Inflation Rate			4.80%	5.00%
Year in which Ultimate Rate is reached			2019	2017

Weighted average assumptions used to determine net benefit obligation for 2013 and 2012 were as follows:

	Pension benefits		OPEB	
	2013	2012	2013	2012
Discount rate	4.55%	3.62%	4.60%	3.75%
Expected return on assets	7.00%	5.50%	5.53%	4.66%
Rate of compensation increase	2.97%	3.09%	2.97%	N/A

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

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

(c) Assumptions (continued)

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 2013 is as follows:

	2013
Effect of a 1 percentage point increase in the HCCTR on:	
Year-end benefit obligation	$ 5,829
Total service and interest cost	580
Effect of a 1 percentage point decrease in the HCCTR on:	
Year-end benefit obligation	$ (4,427)
Total service and interest cost	(456)

(d) Benefit costs

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

	Pension benefits		OPEB	
	2013	2012	2013	2012
Service cost	$ 3,273	$ 1,288	$ 1,602	$ 803
Interest cost	4,350	1,906	1,508	606
Expected return on plan assets	(4,160)	(1,785)	(602)	—
Amortization of net actuarial loss	23	2	26	32
Net benefit cost	$ 3,486	$ 1,411	$ 2,534	$ 1,441

The net actuarial gain for the defined benefit pension plans and OPEB that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year are $283 and $608, respectively.

(e) Plan assets

The Company's investment strategy for its pension and post-retirement 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	79%	48.9%-88.5%
Debt Securities	17%	21.1%-51.1%
Other	4%	0%-11.5%

The fair values of investments as at December 31, 2013, by asset category, are as follows:

Asset Class	Level 1	Percentage
Equity Securities	110,073	79%
Debt Securities	23,173	17%
Other	6,035	4%

As at December 31, 2013, the funds do not hold any material investments in APUC.

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

(f) Cash flows

The Company expects to contribute $7,539 to its pension plans and $1,339 to its post retirement benefit plans in 2014.

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

	2014	2015	2016	2017	2018	2019-2023
Pension plan	$ 8,320	$ 8,238	$ 8,812	$ 9,374	$ 9,839	$ 55,838
OPEB	1,339	1,247	1,400	1,547	1,727	11,176

(g) Defined contribution pension plans

The Company also provides defined contribution pension plans to its employees. The Company's contributions for 2013 were $2,437 (2012 - $1,108).

12. 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 APCo and the legal owner of the St. Leon Wind Facility (note 21). 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 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 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 shares had a nominal carrying amount prior to the exchange. The 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:	
2014	$ 1,109
2015	1,077
2016	946
2017	895
2018	1,125
Thereafter to 2031	20,859
Redemption amount	5,340
	31,351
Less amounts representing interest	(12,546)
	18,805
Less current portion	(1,038)
	$ 17,767

13. Other assets

Other assets consist of the following:

	2013	2012
Restricted cash	$ 6,021	$ 7,063
Deferred financing costs	9,011	8,706
Other	3,752	4,251
	$ 18,784	$ 20,020

14. Other long-term liabilities

Other long-term liabilities consist of the following:

	2013	2012
Asset retirement obligations	$ 9,508	$ 7,088
Customer deposits	8,774	5,620
Provision for injury and damages	1,215	3,480
Deferred water rights inducement	2,764	2,845
Contingent consideration	1,102	1,031
Other	4,580	5,177
	27,943	25,241
Less: current portion	(7,451)	(4,352)
	$ 20,492	$ 20,889

The asset retirement obligations mainly relate to legal requirements to: (i) remove wind farm facilities upon termination of land leases; (ii) cut (disconnect from the distribution system), purge (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.

15. Shareholders' capital

(a) Common shares

Number of common shares:

	2013	2012
Common shares, beginning of period	188,763,486	136,122,780
Conversion and redemption of convertible debentures (i)	150,816	24,991,784
Conversion of subscription receipts (ii)	15,223,016	26,380,750
Issuance of shares under the dividend reinvestment (iii) and employee share purchase plans (c(ii))	2,211,667	1,268,172
Common shares, end of period	206,348,985	188,763,486

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, of which none are authorized or outstanding.

15. Shareholders' capital (continued)

(a) Common shares (continued)

Authorized (continued)

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.

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 of Directors of APUC.

(i) Conversion and redemption of convertible debentures

In 2013, $960 (2012 - $61,611) of Series 3 Debentures were redeemed for 150,816 (2012 - 14,669,266) shares of APUC.

In 2012, the remaining principal amount of $59,957 of Series 2A Debentures were redeemed for 10,322,518 common shares of APUC.

(ii) Subscription receipts

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 May 14, 2012, in connection with the acquisition of Granite State Electric System and EnergyNorth Gas System, the Company issued 12,000,000 common shares at a price of $5.00 per share to Emera pursuant to a subscription receipt agreement. The $60,000 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 the Company received $15,000 from Emera relating to 2,614,006 subscription receipts representing a price of $5.74 per share and issued common shares relating to these subscription receipts in July 2012.

On July 31, 2012, in connection with the acquisition of the Midwest Gas System the Company issued 6,976,744 common shares at a price of $6.45 per share to Emera pursuant to a subscription receipt agreement. The $45,000 cash proceeds of the subscription receipts were used to fund a portion of the cost of the acquisition.

On December 10, 2012, in connection with the acquisition of Senate and Minonk Wind Facilities, the Company received $45,000 from Emera relating to the exercise of 7,842,016 subscription receipts at a price of $5.74 per subscription receipt pursuant to a subscription receipt agreement. The subscription receipts were converted to 7,842,016 common shares on February 14, 2013.

On December 21, 2012, in connection with the acquisition of Emera's noncontrolling interest in Calpeco Electric System, the Company received $38,756 from Emera related to the exercise of 8,211,000 subscription receipts at a price of $4.72 per subscription receipt pursuant to a subscription receipt agreement. On December 27, 2012, Emera exercised 4,790,000 of these subscription receipts and the Company issued 4,790,000 common shares in exchange. On February 14, 2013, the balance of 3,421,000 subscription receipts were exercised by Emera and the Company issued 3,421,000 common shares in exchange.

Following the above noted subscription receipts transactions, as of December 31, 2013 all subscriptions receipts had been exercised for cash and converted to common shares.

15. Shareholders' capital (continued)

(a) Common shares (continued)

(iii) Dividend reinvestment plan

The Company has a Common Shareholder Dividend Reinvestment Plan, which provides an opportunity for shareholders to reinvest dividends for the purpose of purchasing common shares. Additional Common Shares acquired through the reinvestment of cash dividends will be purchased in the open market or will be 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 501,818 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 of Directors of APUC. 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 of Directors of APUC (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 12).

Subsequent to year-end, 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 $3,900.

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 of Directors of APUC (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.

15. Shareholders' capital (continued)

(c) Share-based compensation

For the year ended December 31, 2013, APUC recorded $2,046 (2012 - $1,833) in total share-based compensation expense detailed as follows:

	2013	2012
Stock options	$ 1,687	$ 1,376
Directors deferred share units	155	155
Employee share purchase	75	42
Performance share units	129	260
Total share-based compensation	$ 2,046	$ 1,833

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, 2013, total unrecognized compensation costs related to non-vested options and share unit awards were $1,762 and $86 respectively, and are expected to be recognized over a period of 1.57 years and 1.0 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 historic 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.

15. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(i) Stock option plan (continued)

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

	2013	2012
Risk-free interest rate	1.61%	1.70%
Expected volatility	37%	38%
Expected dividend yield	3.83%	4.40%
Expected life	8 years	8 years
Weighted average grant date fair value per option	$ 2.00	$ 1.49

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, 2012	2,487,105	$ 4.76	6.96	$ 4,134
Granted	1,263,622	6.24	8.00	—
Balance at December 31, 2012	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
Exercisable at December 31, 2013	2,466,008	$ 4.90	4.96	$ 6,018

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. 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 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 shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 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, 2013, a total of 85,410 common shares (2012 – 54,227) were issued to employees under the ESPP plan.

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 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. As at

15. Shareholders' capital (continued)

(c) Share-based compensation (continued)

iii) Directors deferred share units (continued)

December 31, 2013, 74,786 (2012 – 50,172) DSUs were outstanding pursuant to the election of the Directors to defer a percentage of their 2013 and 2012 Director's fee in the form of DSUs.

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. Performance Share Units ("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 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. As the Company does not expect to settle these instruments in cash, these PSUs will be accounted for as equity awards. The Company has a policy of repurchasing shares on the open market to satisfy PSUs exercises and expects to repurchase approximately 24,928 shares during 2014, based on estimates of PSU exercises for that period.

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, 2012	21,123	$ 5.62	2.00	$ 136
Granted	68,982	6.78	1.30	467
Forfeited	(6,622)	5.62	1.50	(37)
Balance at December 31, 2012	83,483	$ 6.58	1.80	$ 571
Granted, including dividends	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
Exercisable at December 31, 2013	24,928	$ 6.14	—	$ 183

16. Accumulated other comprehensive loss

Accumulated other comprehensive loss is comprised of the following balances, net of tax:

	Foreign currency cumulative translation	Unrealized gain on cash flow hedges	Pension and post-retirement actuarial loss	Total
Balance, January 1, 2012	$ (96,462)	$ —	$ (48)	$ (96,510)
Other comprehensive income (loss) before reclassifications	(9,495)	3,596	(2,459)	(8,358)
Amounts reclassified from accumulated other comprehensive loss			1	1
Net current period other comprehensive income	(9,495)	3,596	(2,458)	(8,357)
Balance, December 31, 2012	$ (105,957)	$ 3,596	$ (2,506)	$ (104,867)
Other comprehensive income (loss) before reclassifications	39,422	19,421	16,698	75,541
Amounts reclassified from accumulated other comprehensive loss	—	(2,113)	29	(2,084)
Net current period other comprehensive income	39,422	17,308	16,727	73,457
Balance, December 31, 2013	$ (66,535)	$ 20,904	$ 14,221	$ (31,410)

17. Noncontrolling interests

Net earnings/(loss) attributable to noncontrolling interests consists of the following:

	2013	2012
Net earnings/(loss) attributable to Class B partnership units of SponsorCo	$ 9,556	$ (4,580)
Net earnings/(loss) attributable to Class A partnership units	(20,408)	10,678
Other net earnings attributable to noncontrolling interests	39	1,316
Total net earnings/(loss) attributable to noncontrolling interests	$ (10,813)	$ 7,414

18. Cash dividends

All dividends of the Company are made on a discretionary basis as determined by the Board of the Company. For the year ended December 31, 2013, the Company declared dividends to shareholders on common shares totaling $68,291 (2012 - $50,196) or $0.3325 per common share (2012 - $0.2950 per common share). The Board declared a dividend on the Company's common shares of $0.0850 per share payable on January 15, 2014 to the shareholders of record on December 31, 2013.

For the year ended December 31, 2013, the Company declared and paid dividends to Preferred Share, Series A holders totaling $5,400 (2012 - $769) or $1.125 per Series A Preferred share (2012 - $0.1603 per Series A Preferred share).

19. Income taxes (continued)

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% (2012 – 26.5%). The differences are as follows:

	2013	2012
Expected income tax expense / (recovery) at Canadian statutory rate	$ 16,072	$ 1,726
Increase (decrease) resulting from:		
Recognition of deferred credit	(6,676)	(5,092)
Effect of differences in tax rates on transactions in and within foreign jurisdictions and change in tax rates	(2,338)	(6,282)
Non-taxable corporate dividend	(2,896)	(666)
Noncontrolling interests share of income	4,266	(2,835)
Production tax credit	(247)	(676)
Allowance for equity funds used during construction	(694)	(402)
State taxes	313	—
Other	1,355	(140)
Income tax recovery	$ 9,155	$ (14,367)

For the years ended December 31, 2013 and 2012, income/(loss) from continuing operations before taxes consists of the following:

	2013	2012
Canadian operations	$ 19,687	$ 12,251
U.S. operations	40,962	(5,715)
	$ 60,649	$ 6,536

As a result of the business combination transaction in 2009, APUC recorded certain additional tax attributes. These tax attributes have been recognized to the extent management believes they are more likely than not to be realized. The excess of the carrying amount of the tax attributes recorded over the consideration was recorded as a deferred credit of $55,647 on the transaction date. The deferred credit is being recognized in income as a deferred income tax recovery in relative proportion to the amount of the related tax attributes that are utilized in the period.

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

	Current	Deferred	Total
Year ended December 31, 2013			
Canada	$ 1,532	$ 881	$ 2,413
United States	994	5,748	6,742
	$ 2,526	$ 6,629	$ 9,155
Year ended December 31, 2012			
Canada	$ 127	$ (938)	$ (811)
United States	611	(14,167)	(13,556)
	$ 738	$ (15,105)	$ (14,367)

19. 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 at December 31, 2013 and 2012 are presented below:

	2013	2012
Deferred tax assets:		
Non-capital loss, investment tax credits, currently non-deductible interest expenses, and financing costs	$ 226,314	$ 184,845
Pension and OPEB	31,433	5,011
Acquisition related costs	5,152	5,134
Outside basis in partnership	—	2,533
Regulatory accounts	—	4,013
Financial derivatives	—	211
Environmental obligation	23,076	22,414
Production tax credit	1,633	673
Reserves not currently deductible	2,397	1,276
Other	2,780	136
Total deferred income tax assets	292,785	226,246
Less: Valuation allowance	(15,667)	(15,062)
Total deferred tax assets	277,118	211,184
Deferred tax liabilities:		
Property, plant and equipment	(267,344)	(219,573)
Intangible assets	(8,321)	(5,478)
Outside basis in partnership	(2,210)	—
Regulatory accounts	(24,745)	—
Financial derivatives	(7,675)	—
Total deferred tax liabilities	(310,295)	(225,051)
Net deferred tax assets/(liabilities)	$ (33,177)	$ (13,867)

The valuation allowance for deferred tax assets as of December 31, 2013 was $ (15,667) (2012 $(15,062)). The valuation allowance at December 31, 2013 was primarily related 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:

	2013	2012
Current deferred income tax asset	$ 19,652	$ 10,567
Non-current deferred income tax asset	86,632	77,497
Current deferred income tax liability	(2,308)	(1,133)
Non-current deferred income tax liability	(137,153)	(100,798)
	$ (33,177)	$ (13,867)

19. Income taxes (continued)

As at December 31, 2013, 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 carry forwards
2015	$	5,426
2016 and onwards		463,610
	$	469,036

20. Divestitures

(a) EFW held for sale

During the second quarter of 2013, the Company initiated a strategic review of the Company's business plan and opportunities available for its Energy From Waste ("EFW Thermal Facility") and Brampton Cogeneration Inc. ("BCI Thermal Facility"). As a result of the review, the Company decided to sell the facilities. In the second quarter of 2013, the net assets of 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 $47,651 before tax, or $35,738 net of tax of $11,913.

Subsequent to year-end, on February 7, 2014, the Company entered into an agreement to sell EFW and BCI Thermal Facilities. Accordingly, the determination of the fair value of the net assets of EFW and BCI Thermal Facilites was revised to reflect the estimated selling price, which resulted in a further write down of the net assets of $9,200 before tax, or $6,800 net of tax of $2,400 as at December 31, 2013. The transaction is subject to regulatory approvals, and is expected to close in the first half of 2014. The final selling price is also subject to customary closing adjustments.

(b) Restatement of 2012 comparatives

As a result of the designation of EFW and BCI Thermal Facilities as discontinued operations in 2013, the Company is required to reclassify these assets as discontinued operations in the comparative 2012 financial statements. As a result, the assets, PPE and liabilities have been reclassified to assets held for sale and liabilities held for sale in the 2012 comparative figures. Similarly, the 2012 comparative statement of operations and statement of cash flows have been reclassified to reflect the earnings and cash flow from these assets as discontinued operations. In addition, the 2012 comparative amounts in notes 5, 8, 9, and 19, have also been reclassed from the amounts previously reported in the prior year to reflect this change.

(c) Sale of U.S. Hydro facilities

On June 29, 2013, APCo 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. The sale of the last small U.S. hydroelectric generating facilities is expected to close in 2014 for U.S. $3,600.

In August 2012, APCo sold a small U.S. Hydro facility for gross proceeds of $350 for a loss on sale, net of tax of $253.

20. Divestitures (continued)

(d) Results from discontinued operations

The assets of EFW and BCI Thermal Facilities and the small U.S. hydroelectric facilities are presented as assets held for sale on the consolidated balance sheets and the operating results from these facilities are disclosed as discontinued operations on the consolidated financial statements.

The summary of operating results and cash flows from discontinued operations for the years ended December 31 is as follows:

	2013	2012 as reported	2012 EFW/BCI adjustments	2012 as reclassed
Non-regulated energy sales	9,327	2,870	6,800	9,670
Waste disposal fees	8,160	—	14,288	14,288
Other and interest income	336	—	(6)	(6)
Operating and administrative expenses	(19,720)	(3,241)	(12,544)	(15,785)
Foreign exchange	80	—	—	—
Depreciation of property, plant and equipment	(2,483)	(1,279)	(5,194)	(6,473)
Interest expense	(58)	(4)	(317)	(321)
Gain on sale of assets	1,016	—	—	—
Write-off of accounts receivable	(262)	—	—	—
Write-down of long-lived assets	(56,898)	(253)	(23)	(276)
Gain/(loss) from discontinued operations, before income taxes	(60,502)	(1,907)	3,004	1,097
Income tax recovery/(expense)	18,491	750	(804)	(54)
Gain/(loss) from discontinued operations, net of income taxes	(42,011)	(1,157)	2,200	1,043
Add:				
Depreciation of property, plant and equipment	2,483	1,279	5,194	6,473
Write-off of accounts receivable	262	—	—	—
Write-down of long-lived assets	56,898	253	23	276
Net proceeds of disposition	22,052	—	—	—
Contingent liability	(613)	—	—	—
Income tax expense/(recovery)	(18,491)	(750)	804	54
Increase/(decrease) in cash and cash equivalents from discontinued operations	20,580	(375)	8,221	7,846

20. Divestitures (continued)

(a) Results from discontinued operations (continued)

Assets held-for-sale as at December 31, were as follows:

	2013	2012 as reported	2012 EFW/BCI Adjustments	2012 Reclassed
Property, plant and equipment	$ 21,193	$ 24,390	$ 76,437	$ 100,827
Accounts receivable and prepaid expenses	2,734	—	2,510	2,510
Total assets held for sale	$ 23,927	$ 24,390	$ 78,947	$ 103,337
Less current assets held for sale	(23,927)	(24,390)	(2,510)	(26,900)
Non-current assets held for sale	$ —	$ —	$ 76,437	$ 76,437

Liabilities held-for-sale as at December 31, were as follows:

	2013	2012 as reported	2012 EFW/BCI Adjustments	2012 Reclassed
Accounts payable and accrued liabilities	$ 1,471	$ —	$ 1,211	$ 1,211

21. 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 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

As at December 31, 2013, due from related parties include $nil (December 31, 2012 - $816) owed to APUC from the Parties and due to related parties include $nil (December 31, 2012 - $1,811) owed to the Parties.

Prior to 2010, APMI was the manager of Algonquin Power Income Fund ("APIF"); the predecessor organization to APUC; and at the time of the internalization of management, had a number of fees under negotiation as described below:

- APMI was a one of the original developers of the Red Lily I wind project and was entitled to a royalty fee based on a percentage of operating revenue and a development fee from the equity owner of Red Lily I. In 2011, APUC acquired APMI's interest in this royalty.
- As part of the project to re-power the Sanger Thermal Facility in 2008, APUC entered into an agreement with APMI to undertake certain construction management services on the project for a performance based contingency fee.

21. Related party transactions (continued)

Due to and from related parties (continued)

- During 2007, APUC allowed its offer to acquire Clean Power Income Fund to expire and earned a termination fee for which APMI was entitled to a portion thereof.
- During 2008, APMI provided construction supervision services for the construction of the BCI and was entitled to a construction supervision fee on the BCI project.
- As manager of APIF, APMI was entitled to management fees pursuant to a management agreement and the 2009 Q4 management fee was not made to APMI. In addition, pursuant to the management agreement, APMI incurred and was entitled to reimbursement of reasonable expenses in 2009 which was also not reimbursed by APUC.

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 both in full satisfaction of the related party balances.

Equity interests in Rattle Brook, Long Sault, BCI

The Parties own 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 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 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 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.

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 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 4MW 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 (2012 - $nil) 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. The Class B units held by Senior Executives received cash distributions of $nil for the year ended December 31, 2013 (2012 - $175).

On January 1, 2013, the Company issued 100 redeemable Series C preferred shares and exchanged such shares for the 100 Class B units (note 10) 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, 2013 were $310 (2012 - $333). The current office lease for a portion of its head office facilities expires on December 31, 2015. Subsequent to year-end, on January 31, 2014, APUC, through a wholly owned subsidiary, acquired from a third party a new office facility (note 5) which is suitable for meeting the future head office needs of APUC. Upon occupancy of the new head office facilities which is anticipated to occur in 2014, it is expected that the currently occupied premises will be subleased to third parties.

21. Related party transactions (continued)

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. In 2004 APUC remitted $1,300 to an affiliate of APMI as an advance against expense reimbursements (including engine utilization reserves) for APUC's business use of the aircraft. By the end of 2012 the entire advance had been amortized against expense reimbursements and therefore no amortization expense for the year ended December 31, 2013 related to the advance was incurred (2012 - $279). During the year ended December 31, 2013, APUC reimbursed direct costs in connection with the use of the aircraft of $472 (2012 - $598). As of December 31, 2013, the remaining amount of the advance was $nil (December 31, 2012 - $nil) and as a result the Independent Board Committee is satisfied that the advance arrangement has concluded. The Independent Board Committee and the Parties have agreed that all future utilization of chartered aircraft will be undertaken through third party charter operators at fair market value and under arrangements in which the Senior Executives have no interest.

Operations Services

APUC provided supervisory services on a cost recovery basis for one small hydroelectric generating facility where Senior Executives hold an equity interest. The fees paid in relation to the supervisory management services were nominal for the years ended December 31, 2013 and 2012. This agreement terminated on December 31, 2013.

Trafalgar

APCo 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 Board 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.

Other Related Party Transactions

A member of the Board of Directors of APUC is an executive at Emera. Related Party Transactions between APUC and Emera are discussed in the section below titled "Transactions with Emera".

An individual related to an executive of APUC provided market research consulting services to certain subsidiaries of Liberty Utilities. Related Party Transactions between Liberty Utilities and the consultant are discussed in the section below titled "Other".

Transactions with Emera

- For the year ended December 31, 2013, the Energy Services Business sold electricity to Maine Public Service Company ("MPS"), a subsidiary of Emera, amounting to U.S. $6,042 (2012 - U.S. $6,096). 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.
- 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 two years.

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

Other

An individual related to an executive of APUC provided market research consulting services to certain subsidiaries of Liberty Utilities. During the year ended December 31, 2013 APUC paid $29 (2012 -$nil) in relation to these services.

22. 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 during the year. Diluted net income per share is computed using the weighted-average number of common shares and, if dilutive, potential common shares outstanding during the period. Potential common shares consist of the incremental common shares issuable upon the exercise of stock options, PSUs, DSUs, shareholders' rights and convertible debentures. The dilutive effect of outstanding stock options, PSUs, DSUs and shareholders' rights is reflected in diluted earnings per share by application of the treasury stock method while the dilutive effect of convertible debentures is reflected in diluted earnings per share by application of the as if converted method.

The reconciliation of the net income and the weighted average shares used in the computation of basic and diluted earnings per share are as follows:

		2013		2012
Net earnings attributable to shareholders of APUC	$	20,296	$	14,532
Series A preferred shares dividend		5,400		769
Net earnings attributable to common shareholders of APUC	$	14,896	$	13,763
Discontinued operations	$	(42,011)	$	1,043
Net earnings attributable to common shareholders of APUC from continuing operations - Basic and Diluted	$	56,907	$	12,720
Weighted average number of shares				
Basic		204,350,689		158,304,340
Dilutive effect of share-based awards		980,697		605,281
Diluted		205,331,386		158,909,621

The shares potentially issuable as a result of the convertible debentures as well as stock options of 885,418 respectively (2012 – 1,354,531) are excluded from this calculation as they are anti-dilutive.

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 Québec Court of Appeal ordered a subsidiary of APUC to pay approximately $5,400 (including interest) to the government of Québec relating to water lease payments that the APUC subsidiary has been paying to the St. Lawrence Seaway Management Corporation ("Seaway Management") under its water lease with Seaway Management in prior years.

The water lease with Seaway Management contains an indemnification clause which management 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 $6,000. In 2012, the Company paid an amount of $1,884 to the government of Québec 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.

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.

23. Commitments and contingencies (continued)

(a) Contingencies (continued)

ii) 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 Liberty Utilities, 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 or financial position.

The Company estimates the remaining undiscounted, unescalated cost of these MGP-related environmental cleanup activities will be $77,729 which at discount rates ranging from 3.8% to 4.5% represents the recorded accrual of $69,555 at December 31, 2013 (December 31, 2012 - $57,340). Following resolution of certain environmental liabilities subsequent to year-end, the remaining undiscounted, unescalated costs of these MGP-related environmental cleanup activities should be reduced by $4,200 with a corresponding reduction to the related regulatory asset.

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, at December 31, 2013 the Company has reflected a regulatory asset of $80,438 (December 31, 2012 - $59,789) 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:

2014	$	10,111
2015		27,285
2016		17,873
2017		2,128
2018		1,784
Thereafter to 2046		18,548
	$	77,729

(b) Commitments

In addition to the commitments related to the proposed acquisitions disclosed in note 3 the following significant commitments exist at December 31, 2013.

As a result of the dam safety legislation passed in Quebec (Bill C93), 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 15,400 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	$ 64,626	$ 46,865	$ —	$ —	$ —	$ —	$ 111,491
Gas delivery, service and supply agreements	42,125	26,364	13,812	9,869	9,476	54,495	156,141
Service agreements	24,130	24,371	28,922	29,639	27,897	498,342	633,301
Capital projects	49,337	2,260	—	—	—	—	51,597
Operating leases	5,125	4,551	3,944	3,733	3,551	85,213	106,117
Total	$ 185,343	$ 104,411	$ 46,678	$ 43,241	$ 40,924	$ 638,050	$ 1,058,647

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, 2013. 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.

Subsequent to year-end on March 11, 2014, APCo entered into a Turbine Supply Agreement with a counterparty with respect to the Morse Wind Project. Amounts related to this contract are included in the above table.

24. Non-cash operating items

The changes in non-cash operating items from discontinued operations is comprised of the following:

	2013	2012
Accounts receivable	$ (213)	$ (313)
Prepaid expenses	(11)	135
Accrued liabilities	260	(230)
	$ 36	$ (408)

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

	2013	2012
Accounts receivable	$ (49,888)	$ (14,582)
Related party balances	(996)	1,476
Natural gas inventory	(6,330)	—
Supplies and consumable inventory	(525)	(3,621)
Income tax receivable	177	(423)
Prepaid expenses	(485)	(4,764)
Accounts payable	(29,292)	(7,553)
Accrued liabilities	37,023	31,335
Current income tax liability	1,399	131
Net regulatory assets and liabilities	1,098	(5,475)
	$ (47,819)	$ (3,476)

25. Segmented information

APUC has two business units: APCo which owns or has interests in renewable energy facilities and thermal energy facilities and Liberty Utilities which owns and operates utilities in the United States of America providing water, wastewater and local electric and natural gas distribution services.

Within APCo there are two operating segments: Renewable Energy and Thermal Energy. The Renewable Energy division operates the Company's hydro-electric and wind power facilities. The Thermal Energy division operates co-generation, energy from waste, steam production and other thermal facilities.

Within Liberty Utilities there are the following operating segments: Liberty Utilities (West), Liberty Utilities (Central) and Liberty Utilities (East). Liberty Utilities (West) is comprised of Calpeco Electric System and the water distribution and wastewater utilities located in Arizona. Liberty Utilities (Central) is comprised of the Midwest Gas System and the water distribution and wastewater utilities located in Texas, Missouri and Illinois. Liberty Utilities (East) is comprised of the New Hampshire Electric and Gas Systems, Peach State Gas Gystem and New England Gas System.

The development activities of APCo are reported under Renewable Energy or Thermal Energy as appropriate. 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 derivatives instruments not designated in a hedging relationship is not considered in management's evaluation of divisional performance and is therefore allocated and reported in the corporate segment.

The results of operations and assets for these segments are as follows:

25. Segmented information (continued)

Operational segments (continued)

	Year ended December 31, 2013								
	Algonquin Power			Liberty Utilities				Corporate	Total
	Renewable Energy	Thermal Energy	Total	Central	West	East	Total		
Revenue									
Regulated electricity sales and distribution	$ —	$ —	$ —	$ —	$ 77,814	$ 88,342	$ 166,156	$ —	$ 166,156
Regulated gas sales and distribution	—	—	—	78,857	—	182,815	261,672	—	261,672
Regulated water reclamation and distribution	—	—	—	18,242	39,108	—	57,350	—	57,350
Non-regulated energy sales	145,661	34,530	180,191	—	—	—	—	—	180,191
Other revenue	7,058	2,442	9,500	—	22	—	22	400	9,922
Total revenue	152,719	36,972	189,691	97,099	116,944	271,157	485,200	400	675,291
Operating expenses	48,966	8,514	57,480	27,455	36,753	67,264	131,472	—	188,952
Regulated electricity purchased	—	—	—	—	39,750	57,626	97,376	—	97,376
Regulated gas purchased	—	—	—	46,018	—	102,766	148,784	—	148,784
Non-regulated fuel for generation	—	17,151	17,151	—	—	—	—	—	17,151
	103,753	11,307	115,060	23,626	40,441	43,501	107,568	400	223,028
Depreciation of property, plant and equipment	(45,122)	(5,439)	(50,561)	(9,096)	(13,596)	(18,725)	(41,417)	—	(91,978)
Amortization of intangible assets	(2,652)	(856)	(3,508)	(81)	(611)	—	(692)	—	(4,200)
Administration expenses	(13,094)	(223)	(13,317)	(1,677)	(2,541)	(3,259)	(7,477)	(2,724)	(23,518)
Foreign exchange gain	—	—	—	—	—	—	—	567	567
Interest expense	(27,391)	(1,046)	(28,437)	(5,069)	(8,519)	(10,146)	(23,734)	(1,174)	(53,345)
Interest, dividend and other income	1,867	193	2,060	375	1,395	1,458	3,228	2,497	7,785
Loss on sale of asset	(750)	—	(750)	—	—	—	—	—	(750)
Acquisition related costs	(628)	—	(628)	(68)	—	(1,444)	(1,512)	—	(2,140)
Gain/(loss) on derivative financial instruments	(767)	—	(767)	—	—	—	—	5,967	5,200
Earnings from continuing operations before income taxes	15,216	3,936	19,152	8,010	16,569	11,385	35,964	5,533	60,649
Loss from discontinued operations before income taxes	1,128	(61,630)	(60,502)	—	—	—	—	—	(60,502)
Earnings/(loss) before income taxes	$ 16,344	$ (57,694)	$ (41,350)	$ 8,010	$ 16,569	$ 11,385	$ 35,964	$ 5,533	$ 147
Property, plant and equipment	$ 1,364,843	$ 79,828	$ 1,444,671	$ 215,090	$ 387,715	$ 661,228	$ 1,264,033	$ —	$ 2,708,704
Intangible assets	26,802	5,698	32,500	2,709	19,207	—	21,916	—	54,416
Total Assets held for sale	3,860	20,067	23,927	—	—	—	—	—	23,927
Total assets	1,492,144	116,922	1,609,066	285,517	460,209	923,981	1,669,707	193,784	3,472,557
Capital expenditures	46,885	2,631	49,516	28,566	23,743	56,552	108,861	—	158,377
Acquisition of operating entities	2,083	—	2,083	27,545	—	209,386	236,931	—	239,014

25. Segmented information (continued)

Operational segments (continued)

	Year ended December 31, 2012								
	Algonquin Power			Liberty Utilities				Corporate	Total
	Renewable Energy	Thermal Energy	Total	Central	West	East	Total		
Revenue									
Regulated electricity sales and distribution	$ —	$ —	$ —	$ —	$ 71,734	$ 36,723	$ 108,457	$ —	$ 108,457
Regulated gas sales and distribution	—	—	—	25,802	—	49,916	75,718	—	75,718
Regulated water reclamation and distribution	—	—	—	9,127	37,296	—	46,423	—	46,423
Non-regulated energy sales	84,236	30,115	114,351	—	—	—	—	—	114,351
Other revenue	1,925	1,686	3,611	—	152	94	246	—	3,857
Total revenue	86,161	31,801	117,962	34,929	109,182	86,733	230,844	—	348,806
Operating expenses	30,308	8,568	38,876	13,096	35,645	30,209	78,950	—	117,826
Regulated electricity purchased	—	—	—	—	43,861	24,348	68,209	—	68,209
Regulated gas purchased	—	—	—	13,648	—	23,813	37,461	—	37,461
Non-regulated fuel for generation	—	14,589	14,589	—	—	—	—	—	14,589
	55,853	8,644	64,497	8,185	29,676	8,363	46,224	—	110,721
Depreciation of property, plant and equipment	(18,823)	(4,782)	(23,605)	(3,333)	(11,120)	(7,129)	(21,582)	—	(45,187)
Amortization of intangible assets	(2,653)	(831)	(3,484)	(81)	(586)	—	(667)	—	(4,151)
Administration expenses	(9,424)	(2,176)	(11,600)	294	(4,091)	(1,223)	(5,020)	(2,952)	(19,572)
Foreign exchange gain	—	—	—	—	—	—	—	561	561
Interest expense	(15,060)	(1,733)	(16,793)	(96)	(8,066)	(694)	(8,856)	(9,971)	(35,620)
Interest, dividend and other income	2,038	509	2,547	—	2,113	461	2,574	2,118	7,239
Acquisition related costs	(3,155)	21	(3,134)	(1,442)	—	(3,112)	(4,554)	—	(7,688)
Gain/(loss) on derivative financial instruments	(2,954)	—	(2,954)	—	—	—	—	3,187	233
Earnings from continuing operations before income taxes	5,822	(348)	5,474	3,527	7,926	(3,334)	8,119	(7,057)	6,536
Loss from discontinued operations before income taxes	(1,925)	3,022	1,097	—	—	—	—	—	1,097
Earnings/(loss) before income taxes	$ 3,897	$ 2,674	$ 6,571	$ 3,527	$ 7,926	$ (3,334)	$ 8,119	$ (7,057)	$ 7,633
Property, plant and equipment	$ 1,157,062	$ 77,438	$ 1,234,500	$ 151,637	$ 350,053	$ 350,088	$ 851,778	$ —	$ 2,086,278
Intangible assets	29,480	6,132	35,612	2,613	18,556	—	21,169	—	56,781
Total Assets held for sale	24,390	78,947	103,337	—	—	—	—	—	103,337
Total assets	1,272,037	175,926	1,447,963	212,495	464,201	500,374	1,177,070	153,957	2,778,990
Capital expenditures	21,068	10,348	31,416	10,777	23,181	12,488	46,446	67	77,929
Acquisition of operating entities	245,718	—	245,718	128,890	—	295,297	424,187	—	669,905

25. 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 2013 or 2012: Hydro Québec 14% (2012 - 17%), Manitoba Hydro 14% (2012 – 20%), and California PG&E 9% (2012 - 10%). The Company has mitigated its credit risk to the extent possible by selling energy to these large utilities in various North American locations.

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

	2013	2012
Revenue		
Canada	$ 65,380	$ 62,036
United States	609,911	286,770
	$ 675,291	$ 348,806
Property, plant and equipment		
Canada	$ 433,153	$ 395,896
United States	2,275,551	1,690,382
	$ 2,708,704	$ 2,086,278
Intangible assets		
Canada	$ 26,802	$ 29,480
United States	27,614	27,301
	$ 54,416	$ 56,781

Revenues are attributed to the two countries based on the location of the underlying generating and utility facilities.

26. Financial instruments

(a) Fair value of financial instruments

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 cashflow hedge	31,971	31,971	—	—	31,971
Energy contracts not designated as a cashflow hedge	3,737	3,737	—	—	3,737
Cross-currency swap designated as a foreign exchange hedge	109	109	—	109	—
Commodity contracts for regulated operations	482	482	—	482	—
Total derivative financial instruments	36,299	36,299	—	591	35,708
Total financial assets	$ 58,977	$ 62,620	$ —	$ 591	$ 62,029
Long-term liabilities	$ 1,255,588	$ 1,261,340	$ 296,986	$ 964,354	$ —
Derivative financial instruments:					
Energy contracts designated as a cashflow hedge	4,781	4,781	—	—	4,781
Cross-currency swap designated as a foreign exchange 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	$ 1,271,809	$ 1,277,561	$ 296,986	$ 975,794	$ 4,781

26. Financial instruments

(a)Fair value of financial instruments

2012	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	$ 22,757	$ 25,476	$ —	$ —	$ 25,476
Derivative financial instruments:					
Energy contracts designated as a cashflow hedge	12,695	12,695	—	—	12,695
Cross-currency swap designated as a foreign exchange hedge	408	408	—	408	—
Commodity contracts for regulatory operations	147	147	—	147	—
Total derivative financial instruments	13,250	13,250	—	555	12,695
Total financial assets	$ 36,007	$ 38,726	$ —	$ 555	$ 38,171
Long-term liabilities	$ 770,826	$ 785,473	$ 293,348	$ 492,125	$ —
Convertible debentures	960	1,319	1,319	—	—
Derivative financial instruments:					
Energy contracts designated as a cashflow hedge	9,012	9,012	—	—	9,012
Cross-currency swap designated as a foreign exchange hedge	2,078	2,078	—	2,078	—
Interest rate swaps not designated as a hedge	4,778	4,778	—	4,778	—
Energy derivative contracts	287	287	—		287
Commodity contracts for regulated operations	1,661	1,661	—	1,661	—
Total derivative financial instruments	17,816	17,816	—	8,517	9,299
Total financial liabilities	$ 789,602	$ 804,608	$ 294,667	$ 500,642	$ 9,299

26. 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 (a level 2 measurement) at December 31, 2013 and 2012 due to the short-term maturity of these instruments.

Notes receivable fair values 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. Such estimate is significantly influenced by unobservable data and therefore this fair value is subject to estimation risk.

APUC has long-term liabilities at fixed interest rates and variable rates. The estimated fair value is calculated using current interest rates. The fair value of convertible debentures is determined using quoted market price.

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 8.5%. 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, 2013 or 2012.

The Company's Level 3 instruments consist of energy contracts for energy sales. The significant unobservable inputs used in the fair value measurement of energy contracts are the internally developed forward market prices ranging from USD $21.5 to $181 as of December 31, 2013. 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 26(b)(ii) and 26(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, 2013 or 2012.

(b) Derivative instruments

Derivative instruments are recognized on the balance sheet as either assets or liabilities and measured at fair value each reporting period.

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 accounting for these derivative instruments is subject to current 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 accompanying balance sheets. Gains or losses on the settlement of these contracts are included in the calculation of deferred gas costs (note 7 (d)).

26. Financial instruments (continued)

(b) Derivative instruments (continued)

(i) Commodity derivatives – regulated accounting (continued)

The following are commodity volumes, in dekatherms ("dths") associated with the above derivative contracts:

	2013
Financial contracts: Gas swaps	2,734,304
Gas options	2,082,104
	4,816,408

The change in fair value of the derivative instruments is recorded as an offsetting adjustment to regulatory assets and liabilities. 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 accompanying balance sheets:

	2013	2012
Regulatory assets:		
Gas swap contracts	$ 86	$ 1,555
Gas option contracts	$ 208	$ 106
Regulatory liabilities:		
Gas swap contracts	$ 416	$ 90
Gas option contracts	$ 37	$ 57

(ii) Cash flow hedges

APCo 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)
Energy delivered less existing swap	December 2014	U.S. $	32.64	PJM Western HUB
Energy delivered less existing swap	December 2014	U.S. $	25.64	NI HUB
Energy delivered less existing swap	December 2014	U.S. $	27.39	ERCOT North HUB
147,199	December 2016	$	67.36	AESO
1,029,732	December 2022	U.S. $	42.81	PJM Western HUB
4,395,665	December 2022	U.S. $	30.25	NI HUB
4,663,097	December 2027	U.S. $	36.46	ERCOT North HUB

As at December 31, 2013, an amount receivable under the derivatives for Sandy Ridge, Senate and Minonk Wind Facilities of $7,344 (2012 - $nil) was held as collateral by the counterparty.

The effects on the consolidated statements of operations of derivative financial instruments designated as cash flow hedge consist of the following:

	2013	2012
Gain on derivative instruments (ineffective portion)	$ 1,304	$ 105

26. Financial instruments (continued)

(b) Derivative instruments (continued)

(ii) Cash flow hedges (continued)

The following table summarizes changes in other comprehensive income attributable to derivative financial instruments designated as a hedge:

	2013	2012
Effective portion of cash flow hedge, gain	$ 17,338	$ 5,217
Gain (loss) realized on cash flow hedge	(30)	(49)
	$ 17,308	$ 5,168
Less noncontrolling interest	(9,064)	(1,572)
Change in fair value of cash flow hedge in other comprehensive income attributable to shareholders of Algonquin Power & Utilities Corp.	$ 8,244	$ 3,596

The Company expects $4,949 of unrealized gains currently in accumulated other comprehensive loss to be reclassified into net earnings 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 debentures offering in December 2012, APCo entered into a cross currency swap, coterminous with the debentures, to effectively convert the Canadian dollar denominated offering into U.S. dollars. APCo designated the entire notional amount of the cross currency fixed for fixed interest rate swap and related short-term USD payables created by the monthly accruals of the swap settlement as a hedge of the foreign currency exposure of its net investment in APCo'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 USD 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 other comprehensive income) related to the net investment. A foreign currency loss of $5,771 was recorded in other comprehensive income in 2013.

(iv) Other derivatives

APCo 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
19,440	February 2014	U.S. $	61.40	$ 1,833
69,154	March 2015	U.S. $	48.83	1,729

26. Financial instruments (continued)

(b) Derivative instruments (continued)

(iv) Other derivatives (continued)

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

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

	2013	2012
Change in unrealized loss/(gain) on derivative financial instruments:		
Interest rate swaps	$ (1,598)	$ (2,197)
Energy derivative contracts	(3,809)	(825)
Total change in unrealized loss/(gain) on derivative financial instruments	$ (5,407)	$ (3,022)
Realized loss/(gain) on derivative financial instruments:		
Foreign exchange contracts	$ —	$ (187)
Interest rate swaps	2,024	2,094
Energy derivative contracts	(466)	987
Total realized loss on derivative financial instruments	$ 1,558	$ 2,894
Loss/(gain) on derivative financial instruments accounted for as hedges	$ (3,849)	$ (128)
Ineffective portion of derivatives financial instruments accounted for as hedges	$ (1,351)	(105)
Gain on derivative financial instruments	$ (5,200)	$ (233)

(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 to 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.

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 and notes receivable. 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.

26. Financial instruments (continued)

(c) Risk management (continued)

The remaining revenue is primarily earned by the Utility Services business unit which consists of water and wastewater utilities, electric utilities and gas utilities in the United States. In this regard, the credit risk related to Utility Services accounts receivable balances of U.S. $101,867 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 Company's utilities allow for a reasonable bad debt expense to be incorporated in the rates and therefore ultimately recoverable from rate payers.

As at December 31, 2013 the Company's maximum exposure to credit risk for these financial instruments was as follows:

	December 31, 2013	
	Canadian $	**US $**
Cash and cash equivalents and restricted cash	$ 3,465	$ 15,415
Accounts receivable	18,948	137,481
Allowance for Doubtful Accounts	—	(7,955)
Notes Receivable	20,529	2,021
	$ 42,942	$ 146,962

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 assess each counterparty's ability to perform on the transactions set forth in the contracts.

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 at December 31, 2013, in addition to cash on hand of $13,839 the Company had $202,665 available to be drawn on its senior debt facilities. The senior credit facilities contain covenants which may limit amounts available to be drawn.

26. Financial instruments (continued)

(c) Risk management (continued)

The Company's liabilities mature as follows:

	Due less than 1 year	Due 2 to 3 years	Due 4 to 5 years	Due after 5 years	Total
Long term debt obligations	$ 8,339	$ 147,076	$ 171,907	$ 928,266	$ 1,255,588
Advances in aid of construction	1,239		—	77,697	78,936
Interest on long term debt	54,804	103,605	89,966	168,448	416,823
Purchase Obligations	156,905		—	—	156,905
Environmental obligation	10,111	45,158	3,912	18,548	77,729
Derivative financial instruments:					
Cross- currency swap	—	—	—	7,947	7,947
Interest rate swaps	1,936	1,244	—	—	3,180
Energy derivative and commodity contracts	240	72	—	4,465	4,777
Capital lease payments	125	3,919	—	—	4,044
Other obligations	7,326	—	—	13,809	21,135
Total obligations	$ 241,025	$ 301,074	$ 265,785	$ 1,219,180	$ 2,027,064

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.

APCo designates the amounts drawn on its bank credit facility denominated in U.S. dollars as a hedge of the foreign currency exposure of its net investment in APCo's U.S. operations. The foreign currency transaction gain or loss on the outstanding U.S. dollar denominated balance of APCo's facility that is designated a hedge of the net investment in its foreign operations is reported in the same manner as a translation adjustment (in other comprehensive income) related to the net investment, to the extent it is effective as a hedge. A foreign currency loss of $1,607 was recorded in other comprehensive income.

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 facility, its interest rate swaps as well as interest earned on its cash on hand. The Company does not currently hedge that risk.

APCo is party to an interest rate swap whereby, the Company pays a fixed interest rate of 4.47% on a notional amount of $62,706 and receives floating interest at 90 day CDOR, up to the expiry of the swap in September 2015. At December 31, 2013, the estimated fair value of the interest rate swap was a liability of $3,180 (2012 – liability of $4,778). 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.

27. Comparative figures

Certain of the comparative figures have been reclassified to conform to the financial statement presentation adopted in the current year.

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, 2013. The Management Discussion & Analysis ("MD&A") should be read in conjunction with APUC's audited consolidated financial statements for the years ended December 31, 2013 and 2012. 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 28, 2014.

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 metric 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 metric 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 metric 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 metric 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 metric 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 $0.085 per share or $0.34 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 conducts its business primarily through two autonomous subsidiaries: Algonquin Power Co. ("APCo") which owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation utility assets; and Liberty Utilities Co. ("Liberty Utilities"), a diversified rate regulated utility which owns and operates a portfolio of North American electric, natural gas and water distribution and wastewater collection utility systems.

Algonquin Power Co.

APCo 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. APCo seeks to deliver continuing growth through development of new Greenfield power generation projects and accretive acquisitions of additional electrical energy generation facilities.

APCo owns or has interests in hydroelectric facilities with a combined generating capacity of approximately 125 MW. APCo also owns or has interests in wind powered generating stations with a combined generating capacity of 650 MW. Approximately 82% of the electrical output from the hydroelectric and wind generating facilities is sold pursuant to long term contractual arrangements which have a weighted average remaining contract life of 14 years.

APCo owns or has interests in thermal energy facilities with approximately 350 MW of installed generating capacity. Approximately 93% 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 6 years.

APCo also has a pipeline of development projects that between 2014 and 2016 will add approximately 323 MW of generation capacity from wind powered generating stations and approximately 30 MW from photovoltaic solar powered generation stations with an average contract life of 22 years.

Liberty Utilities Co.

Liberty Utilities is a diversified rate regulated utility providing electricity, natural gas, water distribution and wastewater collection utility services to approximately 480,000 connections. Liberty Utilities 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, Liberty Utilities delivers continued growth in earnings through accretive acquisition of additional utility systems.

The utility systems owned by Liberty Utilities operate under rate regulation, generally overseen by the public utility commissions of the states in which they operate. Liberty Utilities reports the performance of its utility operations through three regions – West, Central, and East.

The Liberty Utilities (West) region is comprised of regulated electrical and water distribution and wastewater collection utility systems. The regulated electrical distribution utility and related generation assets (the "CalPeco Electric System") serve approximately 47,800 electric connections in the State of California. Liberty Utilities (West) region's regulated water and wastewater utility systems serve approximately 68,000 water and wastewater connections located in the State of Arizona.

The Liberty Utilities (Central) region is comprised of regulated natural gas and water distribution and wastewater collection utility systems. The regulated natural gas utilities serve approximately 85,600 natural gas connections located in the States of Missouri, Illinois, and Iowa. Liberty Utilities (Central) region's regulated water distribution and wastewater collection utilities serve approximately 29,400 water and wastewater customers located in the States of Arkansas, Illinois, Missouri, and Texas.

Liberty Utilities (East) region is comprised of regulated natural gas and electric distribution utility systems located in the State of New Hampshire, and regulated natural gas distribution utility systems located in the States of Georgia and Massachusetts. Liberty Utilities provides regulated local electrical utility services to approximately 43,800 electric connections in the state of New Hampshire; and regulated local gas distribution utility services to approximately 206,200 natural gas connections located in the states of Georgia, New Hampshire and Massachusetts.

Major Highlights

2013 Corporate Highlights

Dividend Increased to $0.34 per Common Share Annually

APUC has completed several acquisitions and has advanced a number of other initiatives 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 May 9, 2013, the Board approved a dividend increase of $0.03 per share annually bringing the total annual dividend to $0.34, paid quarterly at the rate of $0.085 per common share.

Management believes that the increase in the 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.

Credit Rating Upgrade

In the fourth quarter of 2013, Standard & Poor's Ratings Services raised its long-term corporate credit rating on APUC, APCo and Liberty Utilities to 'BBB' from 'BBB-'. As well, Standard & Poor's raised its global scale and Canada scale preferred stock ratings on APUC to 'BB+' and 'P-3 (High)' from 'BB' and 'P-3', respectively.

According to Standard & Poor's, the upgrade reflects a significant increase in regulated cash flow from Liberty Utilities owing to a number of acquisitions in the past 18 months, as well as an expectation that adjusted funds from operations-to-debt levels will continue to increase in the near-to-medium term. Standard & Poor's has also provided a stable outlook for the company owing to the assessment of relatively stable cash flows, supported by regulated cash flow from Liberty's regulated utility business, and APCo's largely contracted power asset portfolio.

The Company expects the rating to further improve access to the debt capital markets, reduce credit charges and a lower the overall cost of capital of the Company.

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 initiated in 2011 has now been completed and all related party transactions between APUC and the CEO and Vice Chair have been resolved to the satisfaction of the Independent Board Committee and the Board. The resolution of the related party matters is described in more detail later in this MD&A under "Related Party Transactions".

Strengthened Balance Sheet

Issuance of $100 million Preferred Shares

Subsequent to year-end, on March 5, 2014, APUC issued 4.0 million cumulative rate resent preferred shares, Series D (the "Series D Shares") at a price of $25 per share, for aggregate gross proceeds of $100 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 will be 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.

Emera Share Subscription

Pursuant to previously committed subscription receipts, on February 7, 2013, APUC issued 2.6 million shares at a price of $5.74 per share to Emera Incorporated ("Emera"). Additionally, on February 14, 2013, APUC issued 5.2 million shares at a price of $5.74 per share and 3.4 million shares at a price of $4.72 per share to Emera. On March 26th 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.

As a result, as at December 31, 2013, Emera owns 50.1 million APUC common shares representing approximately 24.2% of the total outstanding common shares of the Company.

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 APUC common shares for the remaining $1.0 million Series 3 Debentures.

APUC Credit Facility

On November 19th, 2013, APUC amended its existing $30.0 million senior unsecured credit facility ("APUC Facility") to increase the commitments available to $65.0 million and extend maturity to November 19, 2016.

2013 Liberty Utilities Highlights

Acquisition of the New England Gas System

On February 11, 2013, Liberty Utilities 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 (“New England Gas System”) 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. The results of the New England Gas System are reported in the Liberty Utilities (East) region.

Total purchase price for the New England Gas System is approximately U.S. $59.1 million, subject to certain working capital and other closing adjustments. 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.

Acquisition of the Peach State Gas System

On April 1, 2013 Liberty Utilities completed the acquisition of regulated natural gas distribution utility systems serving Columbus and Gainesville, Georgia (“Peach State Gas System”, formerly known as Columbus/Gainseville Gas System). The total purchase price for the Peach State Gas System adjusted for certain working capital and other closing adjustments, is approximately U.S. $153.0 million. The regulated natural gas distribution utilities provide natural gas service to approximately 60,000 total connections in Georgia.

Acquisition of the Pine Bluff Water System

On February 1, 2013, Liberty Utilities completed the acquisition of issued and outstanding shares of United Water Arkansas Inc. (“Pine Bluff Water System”), 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, is approximately U.S. $27.9 million.

Acquisition of Remaining Interest in the CalPeco Electric System

On February 14, 2013, APUC issued 3.4 million common shares to Emera representing the balance of the subscription receipts outstanding pursuant to the acquisition in 2012 of the remaining 49.999% ownership in California Pacific Utility Ventures LLC, which owns 100% of the CalPeco Electric System.

U.S. Debt Private Placements

On July 31, 2013, Liberty Utilities 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 Liberty’s revolving credit facility and for general corporate purposes.

On March 14, 2013 Liberty Utilities 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%.

Liberty Utilities Credit Facility

On September 30, 2013, Liberty Utilities increased the credit available under the senior unsecured revolving credit facility (the "Liberty Facility") to U.S. $200.0 million from U.S. $100.0 million. The larger credit facility provides Liberty Utilities with the additional liquidity required resulting from the various acquisitions completed in 2013 and on 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, have improved. The amended facility will now expire on September 30, 2018.

Granite State Electric System Rate Proceedings

On March 29, 2013, the Granite State Electric System with the 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. The filing is based on a 2012 test year, with revenues and expenses adjusted to reflect known and measurable changes. Among other things, Granite State Electric System requested and received approval to continue the current cost-recovery tracking mechanism related to the Reliability Enhancement and Vegetation Management Plan and was granted an annual rate increase of U.S. $0.4 million starting July 1, 2013. The Granite State Electric System also requested a modification to allow for recovery of pre-staging personnel and equipment for qualifying storms. On June 27, 2013, the NHPUC approved a settlement agreement authorizing a temporary annual rate increase of U.S. $6.5 million effective July 1, 2013, and provides recognition for Liberty to request an increase to its storm recovery adjustment factor ("SRAF"). On January 22, 2014, the Granite State Electric System entered a settlement with the New Hampshire PUC Staff, which will provide for a rate increase of U.S. $10.9 million consisting of U.S. $9.8 million in base rates and an additional U.S. $1.1 million for incremental capital expended after the test year. In addition, the settlement allows for one time recovery of rate case expenses of U.S. $0.4 million. It is anticipated that the settlement will be approved in late in Q1 2014.

2013 Algonquin Power Co. Highlights

Agreement to Acquire the Remaining 40% of a 400 MW Wind Power Portfolio

On November 28, 2013, APCo entered into an agreement to acquire the remaining 40% of the 400 MW wind power portfolio (the "U.S. Wind Portfolio") in the United States from Gamesa Wind US, LLC ("Gamesa") for total consideration of approximately U.S. $117.0 million.

APCo currently holds a 60% controlling interest in the U.S. Wind Portfolio which were originally acquired through a newly formed partnership whose original members included APCo, Gamesa and certain tax equity investors. The 400 MW wind portfolio consists of three facilities, Minonk (200MW), Senate (150MW), and Sandy Ridge (50MW) located in the states of Illinois, Texas, and Pennsylvania, respectively.

APCo has been the majority owner and manager of the U.S. Wind Portfolio since 2012 when commercial operation was achieved, therefore no additional ongoing management or administrative costs are expected to be incurred. 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 will be funded primarily from the proceeds from the APCo $200.0 million debentures issued early in 2014.

Acquisition of the 20 MWac Bakersfield Solar Project

On November 28, 2013, APCo entered into an agreement to purchase and complete construction of a 20 MWac Bakersfield Solar Facility ("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 with expected first full year revenues of U.S. $4.7 million. APCo plans to enter 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. It is anticipated that the total expected capital costs for the project of U.S. $58.5 million will be funded as to 55% by APCo and the balance by the Tax Partner. Subject to receipt of final permits and approvals and reaching satisfactory agreement with the Tax Partner, construction of the project is anticipated to commence in the second quarter of 2014 with a commercial operations date expected to occur in late 2014.

Acquisition of Shady Oaks Wind Facility

On January 1, 2013, APCo acquired a 109.5 MW contracted wind powered generating station ("Shady Oaks Wind Facility") by assuming long-term debt of U.S. $150.0 million and for no additional cash, subject to final closing adjustments for working capital, energy generated by the projected 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. Through its affiliate, Goldwind International SO Limited has assumed all operations, maintenance, and capital repair responsibilities for the Shady Oaks Wind Facility pursuant to a 20 year fixed price agreement for the turbines and balance of plant facilities.

Total annual energy production is expected to be 364 GW-hrs per year. 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 will be sold into the energy market in which the facility is located.

Energy From Waste Facility

During the second quarter of 2013, the Company concluded that its Energy from Waste ("EFW") and Brampton Cogeneration Inc. ("BCI") Thermal Facilities 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 its estimated fair value, less cost of sale which resulted in a write down of $35.7 million, net of tax. On February 7, 2014 the Company entered into an agreement to sell the EFW and BCI Thermal Facilities. Accordingly, the determination of the fair values of the net assets of EFW and BCI Themal 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 final selling price is subject to customary closing adjustments. Closing of the transaction is subject to certain regulatory approvals which are expected to be received by the end of the first quarter or early in the second quarter of 2014.

Completion of Cornwall Solar Project

During the second quarter APCo began construction of the 10 MWac solar projected located near Cornwall, Ontario. The facility is the first solar project in APCo's portfolio and is expected to add 13,900 MW-hrs of production annually. Completion of construction is expected late in the first quarter of 2014 at an estimated total capital cost of $45.0 million.

Sale of Small U.S. Hydro Facilities

On March 14, 2013, APCo entered into an agreement to sell ten 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. $27.0 million. APCo closed the sale of nine of the ten facilities on June 28, 2013 for total proceeds of approximately U.S. $23.4 million with the tenth facility expected to be sold in the second quarter of 2014. The operating results from these facilities for current and prior periods are therefore disclosed as discontinued operations on the consolidated statements of operations.

APCo $200 million Senior Unsecured Debentures

On January 17, 2014, APCo issued $200.0 million 4.65% senior unsecured debentures with a maturity date of February 15, 2022 (the "APCo Debentures") pursuant to a private placement in Canada and the United States. The APCo 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, APCo entered into a fixed for fixed cross currency swap, coterminous with the APCo 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 will be 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.

2013 Annual Results from Operations

APUC recorded significant growth in both its regulated and non-regulated utility businesses in 2013. The results for the year reflect the full year of operation from four newly acquired U.S. wind generation facilities and the full year of operation of U.S. gas and electric utilities acquired in 2012 and the additional acquisition of U.S. gas distribution and water distribution utilities in 2013.

Key Selected Annual Financial Information

	Year ended December 31		
(millions of dollars except per share information)	**2013**	**2012**	**2011**
Revenue	**$ 675.3**	$ 348.8	$ 247.5
Adjusted EBITDA [1]	**226.9**	88.1	94.4
Cash provided by operating activities	**98.9**	63.0	69.7
Adjusted funds from operations [1]	**153.5**	66.8	63.6
Net earnings attributable to Shareholders from continuing operations	**62.3**	13.5	22.9
Net earnings attributable to Shareholders	**20.3**	14.5	23.4
Adjusted net earnings [1]	**60.9**	18.9	37.0
Dividends declared to Common Shareholders	**68.3**	50.2	32.4
Weighted Average number of common shares outstanding	**204,350,689**	158,304,340	116,712,934
Per share			
Basic net earnings from continuing operations	**$ 0.28**	$ 0.08	$ 0.20
Basic net earnings	**$ 0.07**	$ 0.09	$ 0.20
Adjusted net earnings [1, 2]	**$ 0.27**	$ 0.11	$ 0.32
Diluted net earnings	**$ 0.07**	$ 0.09	$ 0.20
Cash provided by operating activities [1, 2]	**$ 0.48**	$ 0.40	$ 0.60
Adjusted funds from operations [1, 2]	**$ 0.72**	$ 0.42	$ 0.54
Dividends declared to Common Shareholders	**$ 0.33**	$ 0.30	$ 0.27
Total assets	**3,472.6**	2,779.0	1,282.3
Long term liabilities [3]	**1,255.6**	770.8	455.0

[1] APUC uses adjusted EBITDA, adjusted net earnings and adjusted funds from operations to enhance assessment and understanding of the operating performance of APUC without the effects of certain accounting adjustments which are derived from a number of non-operating factors, accounting methods and assumptions. (see "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] Long term debt includes current and long term portion of debt and convertible debentures.

For the year ended December 31, 2013, APUC experienced an average U.S. exchange rate of approximately $1.0301 as compared to $0.999 in the same period in 2012. 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, 2013, APUC reported total revenue of $675.3 million as compared to $348.8 million during the same period in 2012, an increase of $326.5 million or 93.6%. The major factors resulting in the increase in APUC revenue for the year ended December 31, 2013 as compared to the corresponding period in 2012 are set out as follows:

		Year to date December 31, 2013
		(millions)
Comparative Prior Period Revenue	$	348.8
Significant Changes:		
Liberty Utilities:		
West – Implementation of decoupling mechanism and increased customer demand		4.1
Central – Revenue increase due to the Midstates Gas Systems, and the Pine Bluff Water System acquisitions		59.0
East – Increased revenue resulting from the acquisitions of: the EnergyNorth Gas System, the Granite State Electric System, the Peach State Gas System, and the New England Gas System		176.1
APCo:		
Renewable:		
Acquisition of the Sandy Ridge, Minonk, Senate and Shady Oaks Wind Facilities (collectively, the "U.S. Wind Facilities")		50.5
Sale of Renewable Energy Credits generated from the U.S. Wind Facilities		5.7
Increased demand for retail sales at AES		2.1
St Leon II Wind Facility – Revenue increase from expansion		1.9
Effect of hydrology resource compared to comparable period in prior year		4.5
Thermal:		
Sanger Facility - Increase due to planned shutdown in 2012		4.6
Impact of the stronger U.S. dollar		18.8
Other		(0.8)
Current Period Revenue	$	675.3

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

Adjusted EBITDA in the year ended December 31, 2013 totalled $226.9 million as compared to $88.1 million during the same period in 2012, an increase of $138.8 million or 157.5%. The increase in Adjusted EBITDA was primarily due to acquisitions completed in 2012 and 2013, impact of rate case settlements, increased hydrology and increased customer demand at the CalPeco Electric System. 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, 2013, net earnings from continuing operations attributable to Shareholders totalled $62.3 million as compared to $13.5 million during the same period in 2012, an increase of $48.8 million. The increase was due to $112.3 million in increased earnings from operating facilities, $0.5 million in increased interest, dividend and other income, $5.5 million in decreased acquisition costs, $5.0 million in increased gains from derivative instruments, and $18.2 million in decreased allocations of earnings to non-controlling interests as compared to the same period in 2012. These items were partially offset by $46.8 million increased depreciation and amortization expense, $3.9 million in increased administration charges, $17.7 million in higher interest expense, $0.8 million in increased losses on sale of assets, and $23.5 million in increased income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses).*

For the year ended December 31, 2013, net earnings (including discontinued operations) attributable to Shareholders totalled $20.3 million as compared to $14.5 million during the same period in 2012, an increase of $5.8 million. Net earnings per share totalled $0.07 for the year ended December 31, 2013, as compared to $0.09 during the same period in 2012.

During the year ended December 31, 2013, cash provided by operating activities totalled $98.9 million or $0.48 per share as compared to cash provided by operating activities of $63.0 million, or $0.40 per share during the same period in 2012. During the year ended December 31, 2013, adjusted funds from operations, a non-GAAP measure, totalled $153.5 million or $0.72 per share as compared to adjusted funds from operations of $66.8 million, or $0.42 per share during the same period in 2012 an increase of 86.7 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.

2013 Three month results from operations

Key Selected Fourth Quarter Financial Information

	Quarter ended December 31	
(millions of dollars except per share information)	**2013**	**2012**
Revenue	**$ 205.3**	$ 138.9
Adjusted EBITDA [1]	**67.6**	24.0
Cash provided by operating activities	**31.3**	17.1
Adjusted funds from operations [1]	**45.9**	24.6
Net earnings attributable to Shareholders from continuing operations	**19.8**	6.8
Net earnings attributable to Shareholders	**13.1**	6.4
Adjusted net earnings [1]	**18.5**	6.5
Dividends declared to Common Shareholders	**17.6**	15.5
Weighted Average number of common shares outstanding	**206,219,121**	169,860,332
Per share		
Basic net earnings/(loss) from continuing operations	**$ 0.09**	$ 0.04
Basic net earnings/(loss)	**$ 0.06**	0.03
Adjusted net earnings [1, 2,]	**$ 0.08**	$ 0.03
Diluted net earnings/(loss)	**$ 0.06**	$ 0.05
Cash provided by operating activities [1, 2,]	**$ 0.15**	$ 0.10
Adjusted funds from operations [1, 2]	**$ 0.22**	$ 0.14
Dividends declared to Common Shareholders	**$ 0.09**	$ 0.08

[1] APUC uses adjusted EBITDA, adjusted net earnings and adjusted funds from operations to enhance assessment and understanding of the operating performance of APUC without the effects of certain accounting adjustments which are derived from a number of non-operating factors, accounting methods and assumptions. (see "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, 2013, APUC experienced an average U.S. exchange rate of approximately $1.050 as compared to $0.991 in the same period in 2012. 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, 2013, APUC reported total revenue of $205.3 million as compared to $138.9 million during the same period in 2012, an increase of $66.4 million. The major factors resulting in the increase in APUC revenue in the three months ended December 31, 2013 as compared to the corresponding period in 2012 are set out as follows:

		Quarter ended December 31, 2013
		(millions)
Comparative Prior Period Revenue	$	138.9
Significant Changes:		
Liberty Utilities:		
West – Implementation of decoupling mechanism and increased customer demand		0.3
Central – Revenue increase due to the acquisition of the Pine Bluff Water System and increased customer demand in the Midstates Gas Systems.		5.0
East – Revenue increase due to the acquisition of the Peach State Gas System and the New England Gas System and increased customer demand at the Granite State Electric System and the EnergyNorth Gas System		32.4
APCo:		
Renewable		
Acquisition of the Minonk, Senate and Shady Oaks Wind Facilities		12.1
Sale of Renewable Energy Credits generated from the U.S. Wind Facilities		2.2
Effect of hydrology resource compared to comparable period in prior year		1.1
Increased rates at AES		1.7
St. Leon Wind Facilities - Increased average realized rates		0.9
Thermal		
Increased average price at the Sanger Facility		0.5
Impact of the stronger U.S. dollar		12.0
Other		(1.8)
Current Period Revenue	$	205.3

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

Adjusted EBITDA in the three months ended December 31, 2013 totalled $67.6 million as compared to $24.0 million during the same period in 2012, an increase of $43.6 million or 181.7%. The increase in Adjusted EBITDA was primarily due to acquisitions completed in 2012 and 2013, impact of rate case settlements, increased hydrology and increased customer demand at the CalPeco Electric System. 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, 2013, net earnings attributable to Shareholders from continued operations totalled $19.8 million as compared to $6.8 million during the same period in 2012, an increase of $13.0 million. The increase was due to $28.3 million increased earnings from operating facilities, $0.2 million in decreased administration charges, $0.6 million in decreased acquisition costs, $2.3 million in increased gains from derivative instruments, and $9.7 million decrease in allocations of earnings to non-controlling interests as compared to the same period in 2012. These items were partially offset by $10.5 million increased depreciation and amortization expense, $1.4 million due to a decrease in foreign exchange gain, $3.2 million in higher interest expense, $0.7 million decrease in interest, dividend and other income, $0.6 increased losses on sale of assets, and $11.7 million in increased income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses)* as compared to the same period in 2012.

For the three months ended December 31, 2013, net earnings (including discontinued operations) attributable to Shareholders totalled $13.1 million as compared to net earnings attributable to Shareholders of $6.4 million during the same period in 2012, an increase of $6.7 million. Net earnings per share totalled $0.06 for the three months ended December 31, 2013, as compared to net earnings per share of $0.03 during the same period in 2012.

During the three months ended December 31, 2013, cash provided by operating activities totalled $31.3 million or $0.15 per share as compared to cash provided by operating activities of $17.1 million, or $0.10 per share during the same period

in 2012. During the three months ended December 31, 2013, adjusted funds from operations totalled $45.9 million or $0.22 per share as compared to adjusted funds from operations of $24.6 million, or $0.14 per share during the same period in 2012. The change in adjusted funds from operations in the three months ended December 31, 2013, is primarily due to increased earnings from operations, as compared to the same period in 2012.

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.

APCo: Renewable Energy Division

	Three months ended December 31			Year ended December 31	
	Long Term Average Resource	2013	2012	Long Term Average Resource	2013	2012
Performance (GW-hrs sold)						
Hydro Facilities:						
Ontario Region[7]	**33.8**	**39.3**	7.3	**141.0**	**90.4**	95.4
Quebec Region	**73.1**	**68.0**	70.0	**275.9**	**277.6**	263.4
Maritime Region (incl TPI)	**45.6**	**37.9**	31.6	**177.7**	**203.1**	133.1
Western Region	**12.6**	**12.1**	11.5	**65.0**	**66.6**	64.8
	165.1	**157.3**	120.4	**659.6**	**637.7**	556.7
Wind Facilities:						
Manitoba Region	**121.4**	**116.5**	106.6	**430.2**	**398.0**	405.0
Saskatchewan Region[1]	**24.1**	**22.8**	20.7	**88.0**	**79.1**	82.7
Pennsylvania Region[2]	**43.6**	**38.7**	34.8	**158.3**	**138.8**	55.9
Illinois Region[3]	**296.2**	**271.5**	46.8	**1,037.4**	**938.8**	46.8
Texas Region[4]	**140.0**	**133.8**	33.9	**520.4**	**524.5**	33.9
	625.3	**583.3**	242.8	**2,234.3**	**2,079.2**	624.3
Total	**790.4**	**740.6**	363.2	**2,893.9**	**2,716.9**	1,181.0

Revenue[5]	(millions)	(millions)	(millions)	(millions)
Energy sales	**$ 40.3**	$ 22.9	**$ 145.6**	$ 84.2
Less:				
Cost of Sales – Energy[6]	**(3.8)**	(1.7)	**(8.8)**	(8.9)
Net Energy Sales	**$ 36.5**	$ 21.2	**$ 136.8**	$ 75.3
Renewable Energy Credits	**2.3**	0.2	**5.7**	0.2
Other Revenue	**0.3**	0.6	**1.4**	1.7
Total Net Revenue	**$ 39.1**	$ 22.0	**$ 143.9**	$ 77.2
Expenses				
Operating expenses	**(11.3)**	(5.3)	**(40.1)**	(21.4)
Interest and Other income	**0.5**	0.5	**1.9**	2.0
HLBV income/(loss)	**6.8**	(9.5)	**20.4**	(10.7)
Division operating profit	**$ 35.1**	$ 7.7	**$ 126.1**	$ 47.1

[1] 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.

[2] Represents the operations of the Sandy Ridge Wind Facility which was acquired on July 1, 2012.

[3] Represents the operations of the Minonk and the Shady Oaks Wind Facilities which were acquired on December 10, 2012 and January 1, 2013, respectively. Production at the Shady Oaks was 88.7 GWhrs in the 3 month period and 317.1 GWhrs in the 12 month period ended December 31, 2013. Production at Shady Oaks can be subject to congestion related curtailment by the independent system operator but in this case compensation is expected to be received for lost energy sales.

[4] Represents the operations of the Senate Wind Facility which was acquired on December 10, 2012.

[5] While most of APCo'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.

[6] Cost of Sales - Energy consists of energy purchases by Algonquin Energy Services ("AES") which is resold to its retail and industrial customers. Under GAAP, in APUC's year-end consolidated Financial Statements, these amounts are included in operating expenses.

[7] APCo's Long Sault hydro facility was offline during most of the first nine months of 2013 but with lost revenue covered by insurance. See below for additional commentary

2013 Annual Operating Results

Production data, revenue and expenses have been adjusted to remove the results of the New York and New England Hydro Facilities which are now disclosed as discontinued operations. See Financial Statement note 20 for details.

For the twelve months ended December 31, 2013, the Renewable Energy Division produced 2,716.9 GW-hrs of electricity, as compared to 1,181.0 GW-hrs produced in the same period in 2012, an increase of 130.1%. The increased generation is primarily due to the acquisition of Sandy Ridge, Minonk, Senate, and Shady Oaks Wind Facilities. This level of production represents sufficient renewable energy to supply the equivalent of 201,200 homes on an annualized basis with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 1,992,400 tons of CO_2 gas was prevented from entering the atmosphere in the twelve months ended 2013.

Adjusting for the effect of the unplanned outage at APCo's Long Sault Hydro Facility generating station, during the twelve months ended December 31, 2013, the division generated electricity equal to 95.3% of long-term projected average resources (wind and hydrology) as compared to 92.8% during the same period in 2012. As a result, the division's operating profit for the twelve months ended December 31, 2013 is $11.0 million lower than what would have been generated had the facilities achieved their expected long term average production. In the twelve months of 2013, the Maritime region's operating facilities produced 14% above long-term average resources; while the Quebec, Western, and Texas regions produced 1% to 5% higher than long-term average resources. The Ontario, Manitoba, Saskatchewan, Pennsylvania, and Illinois regions experienced resources lower than long-term average resources, producing 10% to 15% below long-term average resources.

For the twelve months ended December 31, 2013, revenue from energy sales in the Renewable Energy Division totalled $145.6 million, as compared to $84.2 million during the same period in 2012, an increase of $61.4 million. As the purchase of energy by the Algonquin Energy Services ("AES) Business is a significant revenue driver and component of variable operating expenses, the division compares 'net energy sales' (see non-GAAP Financial Measures) as a more appropriate measure of the division's sales results. For the twelve months ended December 31, 2013, net energy sales in the Renewable Energy Division totalled $136.8 million, as compared to $75.3 million during the same period in 2012.

Revenue from generation at APCo's hydro facilities located in the Ontario (excluding Long Sault), Quebec and Western regions increased by $3.1 million primarily as a result of better hydrology in the Quebec Region and Dickson Dam. Lost production from the unplanned shutdown at the Long Sault generating facility in Ontario was largely covered by business interruption insurance claim proceeds and hence did not have a significant impact on 2013 results. Revenue from APCo's hydro facility located in the Maritime region increased by $0.4 million primarily due to a $2.0 million increase in production due to better hydrology, offset by a $1.6 million decrease in weighted average energy rates, as compared to the same period in 2012.

Revenue from APCo's wind facilities located in the Manitoba region increased $1.6 million due primarily to $1.9 million from the expansion of St. Leon Wind Facility, offset partially by $0.3 million due to lower wind resources. Revenues from APCo's Sandy Ridge Wind Facility located in the Pennsylvania region increased $3.7 million as compared to the same period in 2012 as the facility was acquired on July 1, 2012. Revenues from APCo's wind facilities located in the Texas and Illinois regions increased by $48.4 million given that these facilities were acquired in December 2012 and January 2013.

Revenue at AES increased $2.3 million or 11% primarily due to increased customer load served. Revenue at AES primarily consists of 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 Facility and other revenue.

For the twelve months ended December 31, 2013 , energy purchase costs by AES totalled $8.8 million as compared to $8.9 million during the same period in 2012, a decrease of $0.1 million. AES' energy purchase costs for the twelve months ended December 31, 2013 was primarily due to a lower volume of energy purchases from external suppliers due to increased power supplied from the Tinker facility, partially offset by higher average prices. During this period, AES purchased approximately 91.6 GW-hrs of energy at market and fixed rates averaging U.S. $93.4 per MW-hr. During the twelve months, the Maritime region generated approximately 67% of the energy required to service its customers as well as AES' customers, as compared to 44% in the same period in 2012.

For the twelve months ended December 31, 2013 , Renewable Energy Credits ("REC") revenue totalled $5.7 million as compared to $0.2 million in the same period in 2012, representing an increase of $5.5 million. REC units are generated at a ratio of one REC unit per one MWHr generated and are sold in the market in which the REC is generated. For the twelve months ended December 31, 2013 , REC units and related revenue units were generated at the Sandy Ridge, Minonk, Senate and Shady Oaks Wind Facilities.

The Red Lily I Wind Facility located in Saskatchewan produced 79.1 GW-hrs of electricity for the twelve months ended December 31, 2013 . APCo's economic return from its investment in Red Lily I Wind Facility 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, APCo has the right to exchange these contractual and debt interests in Red Lily I Wind Facility for a direct 75% equity interest in 2016. For the twelve months ended December 31, 2013 , APCo earned fees of $1.2 million (which is classified as other revenue) and interest income of $1.6 million from Red Lily I.

For the twelve months ended December 31, 2013 , operating expenses excluding energy purchases totalled $40.1 million, as compared to $21.4 million during the same period in 2012, an increase of $18.7 million. The higher expenses were primarily due to the newly acquired Sandy Ridge, Senate, Minonk, and Shady Oaks Wind Facilities partially offset by lower lease and water usage costs at the Long Sault and Cote St. Catherine Hydro Facilities.

For the twelve months ended December 31, 2013 , interest and other income totalled $1.9 million, as compared to $2.0 million in the same period in 2012. 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 APCo's earnings from its investment in Red Lily I Wind Facility, as discussed above.

Hypothetical Liquidation at Book Value ("HLBV") income represents the value of the net tax attributes generated by APCo 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, 2013 amounted to an approximate HLBV income of $20.4 million as compared to an HLBV loss of $10.7 million during the same period in 2012. The prior year HLBV loss was primarily a result of the accelerated depreciation election that was available in the first year of operations.

For the twelve months ended December 31, 2013 , the Renewable Energy Division's operating profit totalled $126.1 million , as compared to $47.1 million during the same period in 2012, representing an increase of $79.0 million. As a result of the stronger U.S. dollar, operating profit increased by $1.4 million.

2013 Fourth Quarter Operating Results

For the quarter ended December 31, 2013, the Renewable Energy Division produced 740.6 GW-hrs of electricity, as compared to 363.2 GW-hrs produced in the same period in 2012, an increase of 103.9%. The increased generation is primarily due to the acquisition of the Minonk, Senate and Shady Oaks Wind Facilities. This level of production represents sufficient renewable energy to supply the equivalent of 164,400 homes on an annualized basis with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 407,330 tons of CO_2 gas was prevented from entering the atmosphere in the fourth quarter 2013.

Adjusting for the effect of the unplanned outage at APCo's Long Sault generating station during the quarter ended December 31, 2013, the division generated electricity equal to 92.6% of long-term projected average resources (wind and hydrology) as compared to 89.5% during the same period in 2012. As a result, the division's operating profit for the quarter ended December 31, 2013 is $6.3 million lower than what would have been generated had the facilities achieved their expected long term average production. In the fourth quarter of 2013, the Texas and Ontario regions operating facility produced 4% above long-term average resources; while Quebec and Western regions produced 4% to 7% lower than long-term average resources. The Maritime, Saskatchewan, Manitoba, Pennsylvania and Illinois regions were 12% to 19% below long-term average resources.

For the quarter ended December 31, 2013, revenue from energy sales in the Renewable Energy Division totalled $40.3 million , as compared to $22.9 million during the same period in 2012, for an increase of $17.4 million. As the purchase of energy by AES is a significant revenue driver and component of variable operating expenses, the division compares 'net

energy sales' (see non-GAAP Financial Measures) as a more appropriate measure of the division's sales results. For the quarter ended December 31, 2013, net energy sales in the Renewable Energy Division totalled $36.5 million, as compared $21.2 million during the same period in 2012.

Revenue from generation at APCo's hydro facilities located in the Ontario (excluding Long Sault), Quebec and Western regions totalled $6.7 million which was consistent with the same period in 2012. The Long Sault generating facility in Ontario, returned to full operation in the third quarter resulting in an increase of $3.0 million from generation as compared to $1.8 million received from business interruption insurance in the same period in 2012. Revenue from APCo's hydro facility located in the Maritime region increased $0.2 million primarily due to increase in weighted average energy rates.

Revenue from APCo's wind facilities located in the Manitoba region increased $0.8 million due to higher wind resources at St. Leon Wind Facility. Revenues from APCo's Sandy Ridge Wind Facility located in the Pennsylvania region increased $0.3 million as compared to the same period in 2012. Revenue from APCo's wind facilities located in the Texas and Illinois regions increased $12.5 million as the facilities were acquired in the fourth quarter of 2012 and first quarter of 2013.

For the three month ended December 31, 2013, revenue at AES increased $1.8 million or 46% primarily due to increased customer load served. Revenue at AES primarily consists of 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 Facility and other revenue.

For the quarter ended December 31, 2013, energy purchase costs by AES totalled $3.8 million as compared to $1.7 million during the same period in 2012, an increase of $2.1 million. AES' increased energy purchase costs for the quarter ended December 31, 2013 was primarily due to a higher volume of energy purchases from external suppliers, at higher average prices. During this period, AES purchased approximately 40.8 GW-hrs of energy at market and fixed rates averaging U.S. $88 per MW-hr. During the quarter, the Maritime region generated approximately 44% of the load required to service its customers as well as AES' customers, as compared to 52% in the same period in 2012.

For the quarter ended December 31, 2013, REC revenue totalled $2.3 million as compared to $0.2 million in the same period in 2012, representing an increase of $2.1 million. REC units are generated at a ratio of one REC unit per one MWHr generated and are sold in the market in which the REC is generated. For the quarter ended December 31, 2013, REC units and related revenues were generated at the Sandy Ridge, Minonk, Senate and Shady Oaks Wind Facilities.

The Red Lily I Wind Facility located in Saskatchewan produced 22.8 GW-hrs of electricity for the quarter ended December 31, 2013. APCo'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, APCo has the right to exchange these contractual and debt interests in Red Lily I Wind Facility for a direct 75% equity interest in 2016. For the quarter ended December 31, 2013, APCo earned fees of $0.2 million (which is classified as other revenue) and interest income of $0.4 million from Red Lily I Wind Facility.

For the quarter ended December 31, 2013, operating expenses excluding energy purchases totalled $11.3 million, as compared to $5.3 million during the same period in 2012, an increase of $6.0 million. The increase was primarily driven by the increase in costs as a result of the newly acquired Senate, Minonk, and Shady Oaks Wind Facilities.

For the quarter ended December 31, 2013, interest and other income totalled $0.5 million, consistent with the same period in 2012. 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 APCo's earnings from its investment in Red Lily I Wind Facility, as discussed above.

Hypothetical Liquidation at Book Value ("HLBV") income represents the value of net tax attributes generated by APCo in the period from certain of its U.S. wind power generation facilities. The value of net tax attributes generated in the quarter ended December 31, 2013, amounted to an approximate HLBV income of $6.8 million as compared to HLBV loss of $9.5 million. The prior year HLBV loss was primarily a result of the accelerated depreciation election that was available in the first year of operations.

For the quarter ended December 31, 2013, the Renewable Energy Division's operating profit totalled $35.1 million, as compared to $7.7 million during the same period in 2012, representing an increase of $27.4 million. As a result of the stronger U.S. dollar operating profit increased by $0.7 million.

APCo: Thermal Energy Division

	Twelve months ended December 31, 2013			Twelve months ended December 31, 2012		
	Windsor Locks	Sanger	Total	Windsor Locks	Sanger	Total
Performance(GW-hrs sold)	**115.3**	**137.2**	**252.5**	190.2	100.2	290.4
Performance(steam sales – billion lbs)	**623.0**	**—**	**623.0**	602.2	—	602.2
(all amounts in millions)						
Revenue						
Energy/steam sales	**$ 17.7**	**$ 16.9**	**$ 34.6**	$ 17.7	$ 12.4	$ 30.1
Less:						
Cost of Sales – Fuel	**(11.2)**	**(6.0)**	**(17.2)**	(11.7)	(2.9)	(14.6)
Net Energy Sales	**$ 6.5**	**$ 10.9**	**$ 17.4**	$ 6.0	$ 9.5	$ 15.5
Other revenue	**0.5**	**1.9**	**2.4**	0.3	1.4	1.7
Total net revenue	**$ 7.0**	**$ 12.8**	**$ 19.8**	$ 6.3	$ 10.9	$ 17.2
Expenses						
Operating expenses	**(3.7)**	**(4.9)**	**(8.6)**	(4.5)	(4.1)	(8.6)
Facility operating profit	**$ 3.3**	**$ 7.9**	**$ 11.2**	$ 1.8	$ 6.8	$ 8.6
Interest and other income			**0.2**			0.5
Divisional operating profit			**$ 11.4**			$ 9.1

APCo's Sanger and Windsor Locks Thermal Facilities generation 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 facility and regional changes in the average landed cost for natural gas may result in one facility showing increasing costs per unit while the other shows decreasing costs, as 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.

2013 Annual Operating Results

Production data, revenue and expenses have been adjusted to remove the results of the EFW Facility which are now disclosed as discontinued operations. See Financial Statement note 20 for details.

For the twelve months ended December 31, 2013 , the Thermal Energy Division produced 252.5 GW-hrs of energy as compared to 290.4 GW-hrs of energy in the comparable period of 2012. The decrease in energy production was due primarily to the installation of the new Titan turbine at Windsor Locks Thermal Facility which is a smaller, more efficient turbine, sized to optimize the energy and steam requirements of the steam host, and to minimize exposure of the facility to the ISO NE electricity market, compared to the larger Frame 6 turbine that was operating in previous years. This is partially offset by an increased production at Sanger as a result of a planned outage during the first quarter of 2012.

For the twelve months ended December 31, 2013 , the Thermal Energy Division's operating profit was $11.4 million, as compared to $9.1 million during the same period in 2012. The Windsor Locks Thermal Facility contributed $3.3 million, while the Sanger Thermal Facility contributed $7.9 million of operating profit during the twelve months ended December 31, 2013 as compared to $1.8 million and $6.8 million, respectively, during the same period in the prior year. Interest and other income for twelve months ended December 31, 2013 was $0.2 million as compared to $0.5 million during the same period in the prior year a decrease of $0.3 million resulting from lower equity income received from the Valley Power Thermal Facility. As a result of the stronger U.S. dollar, operating profit increased by $0.4 million. Detailed results of each facility are described below.

Windsor Thermal Locks Facility

For the twelve months ended December 31, 2013 , the Windsor Locks Thermal Facility sold 623.0 billion lbs of steam as compared to 602.2 billion lbs of steam in the comparable period of 2012.

Energy/Steam sales at the Windsor Locks Thermal Facility were $17.7 million which was consistent with the same period in 2012. The increase in energy/steam sales is attributed to a higher average price for gas and higher steam production driven by increased customer demand, partially offset by the lower electrical energy production as a result of the newly installed, smaller, more efficient Titan turbine. Natural gas costs for the period were $11.2 million as compared to $11.7 million in the same period in 2012. The decrease in natural gas costs is due to a $2.9 million decrease in the volume of gas consumed as a result of the newly installed, smaller Titan turbine offset by a $2.4 million increase in the average landed cost of natural gas.

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, 2013, net energy sales at the Windsor Locks Thermal Facility totalled $6.5 million, as compared to $6.0 million during the same period in 2012, an increase of $0.5 million.

Operating expenses, excluding natural gas costs were $3.7 million as compared to $4.5 million in the same period in 2012. The decrease in operating expenses was primarily due to the reduced electricity purchases. In 2012, during the planned shutdown, the Windsor Locks Thermal Facility was required to purchase all the electricity requirements for its customer; this additional expense was not required in the current year. The Windsor Locks Thermal Facility's resulting net operating income for the twelve months ended December 31, 2013 was $3.3 million as compared to $1.8 million in the same period in 2012, an increase of $1.5 million.

Sanger Thermal Facility

The Sanger Thermal Facility's operating profit was driven by energy/steam sales of $16.9 million as compared to $12.4 million in the same period in 2012, an increase of $4.5 million. The increase in energy/steam sales is primarily a result of the Sanger Thermal Facility being offline due to a planned outage for three months during the same period in the prior year. The return to operation resulted in an increase of $1.5 million due to increased electrical energy production, and $3.0 million in increased billing rates, as compared to the same period in 2012. Capacity revenues remained unchanged at $8.3 million. Gas costs for the period were $6.0 million as compared to $2.9 million in the same period in 2012. The increase in gas costs is due to an increase in the volume of natural gas consumed, and a 48% increase in the average cost of natural gas per MMBTU.

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, 2013, net energy sales at the Sanger facility totalled $10.9 million, as compared to $9.5 million during the same period in 2012, an increase of $1.4 million.

Operating expenses, excluding natural gas costs were $4.9 million as compared to $4.1 million in the same period in 2012. The increase in operating expenses was due to the Sanger Thermal Facility operating for the twelve months ended December 31, 2013, as opposed to being offline for three months during the same period in 2012. The Sanger facility's resulting net operating income for the twelve months ended December 31, 2013 was $7.9 million, as compared to $6.8 million during the same period in 2012, an increase of $1.1 million.

	Three months ended December 31, 2013			Three months ended December 31, 2012		
	Windsor Locks	Sanger	Total	Windsor Locks	Sanger	Total
Performance(GW-hrs sold)	**28.8**	**35.6**	**64.4**	35.3	35.3	70.6
Performance(steam sales – billion lbs)	**161.3**	**—**	**161.3**	175.3	—	175.3
(all amounts in millions)						
Revenue						
Energy/steam sales	**$ 4.6**	**$ 3.9**	**$ 8.5**	**$ 5.0**	**$ 3.3**	**$ 8.3**
Less:						
Cost of Sales – Fuel	**(3.1)**	**(1.5)**	**(4.6)**	(3.2)	(1.2)	(4.4)
Net Energy/Steam Sales	**$ 1.5**	**$ 2.4**	**$ 3.9**	$ 1.8	$ 2.1	$ 3.9
Other revenue	**0.2**	**0.6**	**0.8**	0.2	0.4	0.6
Total net revenue	**$ 1.7**	**$ 3.0**	**$ 4.7**	$ 2.0	$ 2.5	$ 4.5
Expenses						
Operating expenses	**(0.8)**	**(1.2)**	**(2.0)**	(0.8)	(1.3)	(2.1)
Facility operating profit	**$ 0.9**	**$ 1.8**	**$ 2.7**	$ 1.2	$ 1.2	$ 2.4
Interest and other income			**0.1**			0.3
Divisional operating profit			**$ 2.8**			$ 2.7

2013 Fourth Quarter Operating Results

Production data, revenue and expenses have been adjusted to remove the results of the EFW Facility which is now disclosed as discontinued operations. See Financial Statement note 20 for details.

For the three months ended December 31, 2013 , the Thermal Energy Division produced 64.4 GW-hrs of electrical energy as compared to 70.6 GW-hrs of electrical energy in the comparable period of 2012. The decrease in electrical energy production at the Windsor Locks facility was primarily due to the installation of the new Titan turbine which is a smaller, more efficient turbine, sized to optimize the electricity and steam requirements of the steam host, and to minimize exposure of the facility to the ISO NE electricity market, compared to the larger Frame 6 turbine that was operating in previous years.

For the three months ended December 31, 2013 , the Thermal Energy Division's operating profit was $2.8 million as compared to $2.7 million in the same period in 2012, an increase of $0.1 million. The Windsor Locks Thermal Facility contributed $0.9 million, while the Sanger Thermal Facility contributed $1.8 million of operating profit during the three months ended December 31, 2013 as compared to $1.2 million and $1.2 million, respectively during the same period in the prior year. Interest and other income for three months ended December 31, 2013 was $0.1 million as compared to $0.3 million during the same period in the prior year a decrease of $0.2 million resulting from lower equity income received from the Valley Power Thermal Facility. As a result of the stronger U.S. dollar operating profit increased by $0.2 million. Detailed results of each facility are described below.

Windsor Locks

For the three months ended December 31, 2013 , the Windsor Locks Thermal Facility sold 161.3 billion lbs of steam as compared to 175.3 billion lbs of steam in the comparable period of 2012.

The Windsor Locks Thermal Facility's operating profit was driven by energy/steam sales of $4.6 million which was consistent with the same period in 2012. Gas costs for the period were $3.1 million as compared to $3.2 million in the same period in 2012. The decrease in gas costs is a result of a 4.4% increase on the average landed cost of natural gas per MMBTU offset by a 14.0% decrease in the volume of natural gas consumed, as compared to the same period in 2012.

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, 2013 , net sales at the Windsor Locks Thermal Facility totalled $1.5 million, as compared to $1.8 million during the same period in 2012, a decrease of $0.3 million.

Operating expenses, excluding natural gas costs were $0.8 million which was consistent with the same period in 2012. The Windsor Locks Thermal Facility's resulting net operating income for the three months ended December 31, 2013 was $0.9 million as compared to $1.2 million in the same period in 2012, a decrease of $0.3 million.

Sanger

The Sanger Thermal Facility's operating profit was driven by energy/steam sales of $3.9 million as compared to $3.3 million in the same period in 2012, an increase of $0.6 million. The increase in energy/steam sales is attributed to $0.6 million in increased gas prices which is a pass through to customers as compared to the same period in 2012. Capacity revenues remained unchanged at $1.7 million. Gas costs for the period were $1.5 million as compared to $1.2 million in the same period in 2012. The increase in gas costs is due to an increase in the volume of natural gas consumed, and a 25% increase in the average cost of natural gas per MMBTU as compared to the same period in 2012.

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, 2013, net energy sales at the Sanger Thermal Facility totalled $2.4 million, as compared to $2.1 million during the same period in 2012, an increase of $0.3 million.

Operating expenses, excluding natural gas costs were $1.2 million as compared to $1.3 million in the same period in 2012. The Sanger Thermal Facility's resulting net operating income for the three months ended December 31, 2013 was $1.8 million as compared to $1.2 million in the same period in 2012, an increase of $0.6 million.

APCo: 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 APCo'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. APCo'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 power purchase agreement, 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 APCo will begin construction or execute an acquisition agreement.

Projects Currently in Development

APCo's Development Division has successfully advanced a number of projects and has been awarded or acquired a number of power purchase agreements. The projects are as follows:

Project Name	Location	Size (MW)		Estimated Capital Cost	Commercial Operation	PPA Term	Production GW-hrs
Chaplin Wind [1]	Saskatchewan	177	$	340.0	2016	25	720.0
Amherst Island [2]	Ontario	75	$	230.0	2015	20	247.0
Val Eo - Phase I [1, 6, 7]	Quebec	24	$	70.0	2015	20	66.0
Morse Wind [3, 4]	Saskatchewan	23	$	81.3	2015	20	108.0
Bakersfield Solar [1, 8]	California	20	$	62.2	2015	20	53.3
St. Damase - Phase I [1, 5, 7]	Quebec	24	$	65.0	2014	20	78.7
Cornwall Solar [1, 2]	Ontario	10	$	45.0	2014	20	14.4
Total		**353**	**$**	**893.5**			**1,287.4**

[1] PPA signed

[2] FIT contract awarded

[3] Two 10 MW PPAs; one 5MW PPA

[4] Comprised of three projects that are connected geographically and will be built simultaneously. All three projects were awarded PPAs under the province's Green Options Partner Program ("GOPP").

[5] The St. Damase project is being developed in two phases: Phase I of the project (24MW) will be erected in 2014 and the 101MW 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.

[6] The Val Eo project is being developed in two phases: Phase I of the project (24MW) will be erected in 2015 and the 101 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.

[7] Size, Estimated Capital Costs, Commercial Operation Date, PPA Term and Production refer solely to Phase I of the St. Damase and Val-Eo wind projects.

[8] Total cost the project is expected to be U.S $58.5 million.

Chaplin Wind Project

In the first quarter of 2012, APCo 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 has a targeted commercial operation date of December, 2016. The facility will be constructed at an estimated capital cost of $340 million and consist of approximately 77 multi-megawatt wind turbines. The project is expected to generate first full year 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 favourable location by interconnecting with a nearby 138Kv line and will be compliant with SaskPower's latest interconnection requirements.

The Environmental Impact Assessment was submitted in third quarter of 2013 to the Environmental Assessment Branch, Saskatchewan Environment. Screening was completed, and a proposed layout was requested in order to provide a final determination. A supplemental report was submitted in the fourth quarter of 2013 to address the questions identified during the screening process and the project is awaiting a response from the Environment Assessment Branch. As a result of continuing development work, the expected capital costs of the project have been reduced to $340 million from the original estimate of $355 million. To optimize the returns associated with the project, APCo intends to enter into a partnership agreement using a similar structure to what was utilized in the development of the Red Lily I facility.

Amherst Island Wind Project

The Amherst Island wind project is located on Amherst Island near the village of Stella, approximately 15 kilometres 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. APCo forecasts that the available wind resource could produce approximately 247 GW-hrs of electrical energy annually, depending upon the final turbine selection for the project. Total capital costs for the facility are currently estimated to be $230 million. The financing of the project will be arranged and announced when all required permitting and all other pre-construction conditions have been satisfied. Environmental studies and engineering are underway.

The Renewable Energy Approval ("REA") application was submitted in April 2013 and was posted to the environmental registry in early January 2014. The REA is now anticipated to be received at the beginning of the third quarter of 2014. Subject to receipt of the REA approval as expected, construction is expected to commence shortly thereafter; with a planned construction time frame of 12 to 18 months. Completion is targeted to occur in late 2015 or early 2016.

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

APCo 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 APCo 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 total annual energy production for the Morse Wind Project has increased from 93.0 GW-hrs to 108.0 GW-hrs due to final turbine selection and increased hub height. Accordingly, the capital cost to construct the Morse wind project has also increased and is currently estimated to be $81.3 million, inclusive of acquisition costs. The contract rate is set at $104.02 per MW-hr for the first full year of operations, which APCo expects to occur in 2015, with an annual escalation provision of 2% over the expected 20 year term.

The provincial environmental assessment of the site was completed in the first quarter of 2012 and submitted to the provincial Environmental Assessment agency. In April 2012, the project was deemed a "non-development" by the Provincial Environmental Assessment Branch thereby not requiring further environmental assessment review.

Quebec Community Wind Projects

In December 2010, APCo, in partnership with Société en Commandite Val-Éo, a community cooperative with a development project located in the Lac Saint-Jean region of Quebec, and in partnership with the community of Saint-Damase, were awarded PPAs for the construction of two wind power projects in the Province of Quebec using ENERCON wind turbines. Both projects will represent phase one in the potential development of a larger second phase.

Saint-Damase

Phase one of the Saint-Damase wind project is located in the local municipality of Saint-Damase, which is within the regional municipality of les Maskoutains. The project is a 24MW facility located near St. Damase, Quebec in a partnership with the Municipality of Saint-Damase. The Saint-Damase wind project has signed a 20 year PPA with Hydro Quebec and has projected capital costs of $65 million. On June 25, 2013, the

partnership executed an interconnection agreement with Hydro Quebec. The permitting and the environmental impact assessment are ongoing and the construction of the first project phase is planned for the early second quarter of 2014, with commercial operation for the project expected to commence in late 2014.

APCo's interest in the project will not be less than 50%. The project's social acceptance is strong, and about 50 jobs will be created during construction. The environmental impact assessment for the project has been reviewed and has received the provincial minister's decree allowing the project to proceed with construction. APCo has entered into an agreement for the supply of wind turbines with Enercon Canada Inc. It is believed that the first 24MW phase of the Saint-Damase wind project will qualify as Canadian Renewable conservation expense and therefore the project will be entitled to a refundable tax credit equal to approximately $20.5 million. It is contemplated that a request for a PPA in respect of Phase II of the project will be submitted to Hydro Quebec pursuant to its current request for proposals and if successful would proceed based on the results achieved in Phase I.

Val-Éo

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 APCo. 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 early 2015 with commercial operations commencing in late 2015. The second phase of the project would entail the development of an additional 106 MW. The permitting and the Environmental Impact Assessment are ongoing with a projected provincial minister's decree at the end of 2014.

APCo's 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 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 $22.0 million. It is contemplated that a request for a PPA in respect of Phase II of the project will be submitted to Hydro Quebec pursuant to its current request for proposals and if successful would proceed based on the results achieved in Phase I.

Cornwall Solar Project

In the first quarter of 2012, APCo acquired all of the issued and outstanding shares of Cornwall Solar which owns the rights to develop the Cornwall Project, a 10 MW solar project located near Cornwall, Ontario. In addition to the Cornwall Project, APCo has acquired an option to acquire ten additional Ontario based solar projects.

The Cornwall Project has been granted a 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. The Cornwall Project contemplates the use of a ground-mounted PV array system, installed on two parcels of leased land totalling approximately 138 acres.

The Cornwall Project received its Renewable Energy Approval on January 15, 2013 and its Notice to Proceed on April 29, 2013. Construction of the project began during the second quarter of 2013 with substantial completion expected by the end of the first quarter of 2014 and commercial operation expected to commence in the second quarter of 2014. After completion of the design and start of construction, improvements in engineering layout and module capacity have led to an increase in annual energy production forecast from 13.4 GW-hrs/year to 14.4 GW-hrs/year. Generation in excess of 13.4 GW-hrs/year is paid to the original developer after minimum return thresholds are achieved by APCo.

Bakersfield Solar Project

APCo 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. APCo plans to enter 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. It is anticipated that the total expected capital costs for the project of U.S. $58.5 million will be funded as to 55% by APCo and the balance by the Tax Partner. Subject to receipt of final permits and approvals and reaching satisfactory agreement with the Tax Partner, construction of the project is anticipated to commence in the second quarter of 2014 with a commercial operations date expected to occur in late 2014.

Liberty Utilities

Liberty Utilities is a national diversified rate regulated utility providing electricity, natural gas, water distribution and wastewater collection utility services in the U.S. Liberty Utilities’ strategy is to grow its business organically and through business development activities while using prudent acquisition criteria. Liberty Utilities believes that its business results are maximized by building constructive regulatory and customer relationships, and enhancing community connections.

Utility System Type	December 31, 2013		December 31, 2012	
	Assets	Connections	Assets	Connections
	U.S. $ (millions)		U.S. $ (millions)	
Electricity	$ 276.6	91,600	$ 254.3	91,200
Natural Gas	661.5	291,800	394.8	175,500
Water and Wastewater	233.0	97,400	205.4	78,000
Total	$ 1,171.1	480,800	$ 854.5	344,700
Accumulated Deferred Income Taxes	$ 66.5		$ 53.5	

Liberty Utilities reports the performance of its utility operations by geographic region – West, Central, and East

The Liberty Utilities (West) region is comprised of regulated electrical and water distribution and wastewater collection utility systems and serves approximately 115,800 connections in the states of Arizona and California.

The Liberty Utilities (Central) region is comprised of regulated natural gas and water distribution and wastewater collection utility systems and serves approximately 115,000 connections located in the states of Arkansas, Illinois, Iowa, Missouri, and Texas.

The Liberty Utilities (East) region is comprised of regulated natural gas and electric distribution utility systems and serves approximately 250,000 connections located in the states of Georgia, Massachusetts, and New Hampshire.

Liberty Utilities: West Region

	Year ended December 31,	
	2013	2012
Average Active Electric Connections For The Period		
Residential	41,200	41,300
Commercial and Industrial	5,500	5,600
Total Average Active Electric Connections For The Period	**46,700**	**46,900**
Average Active Water Connections For The Period		
Wastewater connections	30,700	29,700
Water distribution connections	33,900	33,100
Total Average Active Water Connections For The Period	**64,600**	**62,800**
Customer Usage (GW-hrs)		
Residential	281.3	273.6
Commercial and Industrial	277.1	279.1
Total Customer Usage (GW-hrs)	**558.4**	**552.7**
Gallons Provided		
Wastewater treated (millions of gallons)	1,660	1,648
Water sold (millions of gallons)	5,072	5,080
Total Gallons Provided	**6,732**	**6,728**

The Liberty Utilities (West) region's increase in average water and wastewater connections during the period is primarily due to development within the service territory. During the twelve months ended December 31, 2013 , the Liberty Utilities (West) region provided approximately 5,072 million gallons of water to its customers and treated approximately 1,660 million gallons of wastewater as compared to 5,080 million gallons of water and 1,648 million gallons of wastewater during the same period in 2012.

For the twelve months ended December 31, 2013 , electricity usage at the CalPeco Electric System totalled 558.4 GW-hrs, as compared to 552.7 GW-hrs for the same period in 2012, an increase of 5.7 GW-hrs or 1.1%. This increase in usage was primarily due to colder weather experienced in the first quarter of 2013 as compared to warmer weather experienced in the same period a year ago. Under the base rate revenue decoupling mechanism approved by the California Public Utilities Commission ("CPUC"), which became effective on January 1, 2013, the CalPeco Electric System's base rate revenues will not be 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.

	Year ended December 31,		Year ended December 31,	
	2013 U.S. $ (millions)	2012 U.S. $ (millions)	**2013 Can $ (millions)**	2012 Can $ (millions)
Water Assets for regulatory purposes	**179.3**	181.3		
Electricity Assets for regulatory purposes	**175.5**	165.9		
Revenue				
Utility electricity sales and distribution	**$ 75.5**	$ 71.9	**$ 77.8**	$ 71.7
Wastewater treatment	**18.1**	18.3	**18.7**	18.3
Water distribution	**19.8**	19.0	**20.4**	19.0
Other Revenue	**—**	0.2	**—**	0.2
Total Revenue	**$ 113.4**	$ 109.4	**$ 116.9**	$ 109.2
Less:				
Cost of Sales – Electricity	**(38.6)**	(44.0)	**(39.8)**	(43.9)
Net Utility Sales	**$ 74.8**	$ 65.4	**$ 77.1**	$ 65.3
Expenses				
Operating expenses	**(35.6)**	(35.6)	**(36.7)**	(35.6)
Other income	**1.4**	2.1	**1.4**	2.1
Divisional operating profit	**$ 40.6**	$ 31.9	**$ 41.8**	$ 31.8

2013 Annual Operating Results

The Liberty Utilities (West) region has investments in water and wastewater distribution assets for regulatory purposes of U.S. $179.3 million and electricity assets for regulatory purposes of U.S.$175.5 million as at December 31, 2013, as compared to U.S. $181.3 million and U.S .$165.9 million, respectively as at December 31, 2012.

For the twelve months ended December 31, 2013 , the Liberty Utilities (West) region's revenue totalled U.S. $113.4 million as compared to U.S. $109.4 million during the same period in 2012, an increase of U.S. $4.0 million or 3.7%.

For the twelve months ended December 31, 2013 , the Liberty Utilities (West) region's revenue from utility electricity sales totalled U.S. $75.5 million as compared to U.S. $71.9 million during the same period in 2012, an increase of U.S. $3.6 million or 5.0%. This increase in revenues was primarily due to an increase in base revenue requirement approved in the most recent rate case that became effective January 1, 2013 and milder winter and spring weather that occurred in the first part of 2012. 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 will not be impacted by fluctuations in customer demand due to the variations in weather conditions and changes in the number of customers.

For the twelve months ended December 31, 2013 , revenue from wastewater treatment and water distribution totalled U.S. $18.1 million and U.S. $19.8 million respectively, as compared to U.S. $18.3 million and U.S. $19.0 million, respectively, during the same period in 2012. The total wastewater treatment and water distribution revenue increase was due to increased connection counts, which increased fixed and usage revenue.

For the twelve months ended December 31, 2013 , fuel and purchased power costs for the Liberty Utilities (West) region totalled U.S $38.6 million , as compared with U.S. $44.0 million for the same period in 2012. The overall electricity purchase costs experienced a decrease of U.S. $5.4 million primarily as a result of a change in rates effective January 1, 2013 which refunds an over-collection of electricity costs from the prior fiscal period

The purchase of electricity by the Liberty Utilities (West) region is a significant revenue driver and component of operating expenses but these costs are effectively passed through to its customers. As a result, the Liberty Utilities (West) region compares 'net utility sales' (see non-GAAP Financial Measures) as a more appropriate measure of the division's results. For the twelve months ended December 31, 2013 , net utility sales for the Liberty Utilities (West) region were U.S. $74.8 million, as compared to U.S. $65.4 million during the same period in 2012, an increase of $9.4 million, or 14.4% .

For the twelve months ended December 31, 2013 , operating expenses totalled U.S. $35.6 million, which was consistent with the same period in 2012.

For the twelve months ended December 31, 2013 , the Liberty Utilities (West) region's operating profit was U.S $40.6 million as compared to U.S $31.9 million in the same period in 2012, an increase of U.S.$ $8.7 million, or 27.3%.

Measured in Canadian dollars, the Liberty Utilities (West) region's operating profit was $41.8 million as compared to $31.8 million in the same period in 2012.

	Three months ended December 31,	
	2013	2012
Average Active Electric Connections For The Period		
Residential	41,600	41,300
Commercial and Industrial	5,500	5,600
Total Average Active Electric Connections For The Period	**47,100**	**46,900**
Average Active Number of Water Connections For The Period		
Wastewater connections	30,900	30,100
Water distribution connections	34,100	33,400
Total Average Active Water Connections For The Period	**65,000**	**63,500**
Customer Usage (GW-hrs)		
Residential	77.0	72.2
Commercial and Industrial	77.2	81.5
Total Customer Usage (GW-hrs)	**154.2**	**153.7**
Gallons Provided		
Wastewater treated (millions of gallons)	418	423
Water sold (millions of gallons)	1,277	1,256
Total Gallons Provided	**1,695**	**1,679**

For the three months ended December 31, 2013 , the Liberty Utilities (West) region's electricity usage totalled 154.2 GW-hrs, as compared to 153.7 GW-hrs for the same period in 2012, an increase of 0.5 GW-hrs. 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 will not be 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.

During the three months ended December 31, 2013 , the Liberty Utilities (West) region provided approximately 1,277 million gallons of water to its customers and treated approximately 418 million gallons of wastewater, as compared to 1,256 gallons of water and 423 gallons of wastewater during the same period in 2012.

	Three months ended December 31,		Three months ended December 31,	
	2013 U.S. $ (millions)	2012 U.S. $ (millions)	**2013 Can $ (millions)**	2012 Can $ (millions)
Revenue				
Utility electricity sales and distribution	**$ 19.8**	$ 19.5	**$ 20.7**	$ 19.3
Wastewater treatment	**4.2**	4.7	**4.4**	4.7
Water distribution	**5.2**	4.5	**5.5**	4.5
Other Revenue	**—**	—	**—**	—
	$ 29.2	$ 28.7	**$ 30.6**	$ 28.5
Less:				
Cost of Sales – Electricity	**(10.5)**	(11.5)	**(11.0)**	(11.4)
Net Utility Sales	**$ 18.7**	$ 17.2	**$ 19.6**	$ 17.1
Expenses				
Operating expenses	**(8.4)**	(9.3)	**(8.9)**	(9.4)
Other income	**0.2**	1.1	**0.3**	1.1
Division operating profit	**$ 10.5**	$ 9.0	**$ 11.0**	$ 8.8

2013 Fourth Quarter Operating Results

For the three months ended December 31, 2013 , the Liberty Utilities (West) region's revenue totalled U.S. $29.2 million as compared to U.S.$28.7 million during the same period in 2012, an increase of U.S. $0.5 million or 1.7%.

For the three months ended December 31, 2013 , the Liberty Utilities (West) region's revenue from utility electricity sales totalled U.S. $19.8 million as compared to U.S. $19.5 million during the same period in 2012, an increase of U.S. $0.3 million or 1.5%. This increase in revenues was primarily due to an increase in base revenue requirements approved in the most recent rate case that became effective January 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 will not be impacted by fluctuations in customer demand due to the variations in weather conditions and changes in the number of customers.

For the three months ended December 31, 2013 revenue from wastewater treatment and water distribution totalled U.S. $4.2 million and U.S. $5.2 million, respectively, as compared to U.S. $4.7 million and U.S. $4.5 million, respectively, during the same period in 2012. The total wastewater treatment and water distribution revenue was primarily due to an increase in average connection counts, as compared to the same period in 2012.

For the three months ended December 31, 2013 fuel and purchased power costs for the Liberty Utilities (West) region totalled U.S $10.5 million, as compared with U.S. $11.5 million for the same period in 2012, a decrease of $1.0 million. The overall electricity purchase costs experienced a decrease of U.S. $1.0 million primarily as a result of a change in rates effective January 1, 2013 which refunds an over-collection of electricity costs from the prior fiscal period.

The purchase of electricity by the Liberty Utilities (West) region is a significant revenue driver and component of operating expenses but these costs are effectively passed through to its customers. As a result, the Liberty Utilities (West) region compares 'net utility sales' (see non-GAAP Financial Measures) as a more appropriate measure of the division's results. For the three months ended December 31, 2013 net utility sales for the Liberty Utilities (West) region were U.S. $18.7 million, as compared to U.S. $17.2 million during the same period in 2012, an increase of $1.5 million or 8.7%.

For the three months ended December 31, 2013 operating expenses totalled U.S. $8.4 million, as compared to U.S. $9.3 million during the same period in 2012.

For the three months ended December 31, 2013 , the Liberty Utilities (West) region's operating profit was U.S. $10.5 million as compared to U.S. $9.0 million in the same period in 2012, an increase of U.S. $1.5 million or 16.7%.

Measured in Canadian dollars, the Liberty Utilities (West) region's operating profit was $11.0 million as compared to $8.8 million in the same period in 2012.

Liberty Utilities: Central Region

	Year ended December 31,	
	2013	2012
Average Active Natural Gas Connections For The Period		
Residential	71,300	71,500
Commercial and Industrial	9,200	9,500
Total Average Active Natural Gas Connections For The Period	**80,500**	**81,000**
Average Active Water Connections For The Period		
Wastewater connections	5,900	5,800
Water distribution connections	21,900	5,300
Total Average Active Water Connections For The Period	**27,800**	**11,100**
Customer Usage (MMBTU)		
Residential	5,187,000	1,307,000
Commercial and Industrial	3,555,000	1,093,000
Total Customer Usage (MMBTU) [1]	**8,742,000**	**2,400,000**
Gallons Provided		
Wastewater treated (millions of gallons)	374	372
Water sold (millions of gallons) [2]	3,090	383
Total Gallons Provided	**3,464**	**755**

[1] Represents MMBTU since August 1, 2012 acquisition date

[2] Water distribution utility was acquired on February 1, 2013

The Liberty Utilities (Central) region acquired the Pine Bluff Water System on February 1, 2013 and the Midstates Gas System on August 1, 2012, and accordingly, the twelve month results for 2012 are not comparative.

For the twelve months ended December 31, 2013 , the Liberty Utilities (Central) region natural gas distribution sales totalled 8,742,000 MMBTU as compared to 2,400,000 MMBTU during the same period in 2012, an increase of 6,342,000 MMBTU.

During the twelve months ended December 31, 2013 , the Liberty Utilities (Central) region provided approximately 3,090 million gallons of water to its customers, and treated approximately 374 million gallons of wastewater, as compared to 383 million gallons of water and 372 million gallons of wastewater during the same period in 2012.

As a result of the acquisition of the Pine Bluff Water System on February 1, 2013 the number of water connections in the region increased by approximately 17,700. During the twelve months ended December 31, 2013 , the amount of water sold correspondingly increased by 2,613 million gallons.

	Year ended December 31,		Year ended December 31,	
	2013 U.S. $ (millions)	2012 U.S. $ (millions)	**2013 Can $ (millions)**	2012 Can $ (millions)
Natural Gas Assets for regulatory purposes	**148.1**	131.4		
Water Assets for regulatory purposes	**53.7**	24.1		
Revenue				
Utility natural gas sales and distribution [1]	**$ 73.3**	$ 24.8	**$ 75.5**	$ 24.6
Wastewater treatment	**5.8**	5.6	**6.0**	5.6
Water distribution	**11.9**	3.5	**12.2**	3.5
Gas transportation	**3.3**	1.2	**3.4**	1.2
	$ 94.3	$ 35.1	**97.1**	$ 34.9
Less:				
Cost of Sales – Natural Gas [1]	**(44.7)**	(13.8)	(46.0)	(13.6)
Net utility sales	**$ 49.6**	$ 21.3	**$ 51.1**	$ 21.3
Expenses				
Operating expenses	**(26.6)**	(13.1)	**(27.4)**	(13.1)
Interest and other income	**0.4**	—	**$ 0.4**	$ —
Divisional operating profit	**$ 23.4**	$ 8.2	**$ 24.1**	$ 8.2

[1] Represents Natural Gas revenue and gas costs since August 1, 2012 acquisition date.

2013 Annual Operating Results

The Liberty Utilities (Central) region has investments in natural gas distribution assets for regulatory purposes of U.S. $148.1 million and water distribution assets for regulatory purposes of U.S. $53.7 million as at December 31, 2013, as compared to U.S $131.4 million and U.S. $24.1 million, respectively as at December 31, 2013. The increase in natural gas distribution assets for regulatory purposes is primarily related to pipe expansion and replacement activities and system implementations, while the increase in water assets for regulatory purposes is primarily a result of the Pine Bluff Water System acquisition.

For the twelve months ended December 31, 2013 , the Liberty Utilities (Central) region's revenue totalled U.S. $94.3 million as compared to U.S. $35.1 million during the same period in 2012, an increase of U.S. $59.2 million. The increase in revenue is primarily attributed to the addition of the natural gas distribution assets acquired on August 1, 2012 and the Pine Bluff Water System acquired on February 1, 2013.

For the twelve months ended December 31, 2013 , the Liberty Utilities (Central) region's revenue from natural gas sales and distribution totalled U.S. $73.3 million as compared to U.S. $24.8 million during the same period in 2012, an increase of U.S. $48.5 million.

For the twelve months ended December 31, 2013 , the Liberty Utilities (Central) region's revenue from gas transportation sales totalled U.S. $3.3 million as compared to U.S. $1.2 million during the same period in 2012, an increase of U.S. $2.1 million . The increase in transportation revenue is primarily attributed to the addition of the natural gas distribution assets acquired on August 1, 2012.

For the twelve months ended December 31, 2013 , revenue from wastewater treatment and water distribution totalled U.S. $5.8 million and U.S. $11.9 million, respectively, as compared to U.S. $5.6 million and U.S. $3.5 million, respectively, during the same period in 2012. The increase in water distribution revenue is primarily attributed to the addition of the Pine Bluff Water System.

For the twelve months ended December 31, 2013 , natural gas purchases for the Liberty Utilities (Central) region's natural gas utility totalled U.S $44.7 million , as compared with U.S. $13.8 million for the same period in 2012. The overall natural gas purchase costs experienced an increase of U.S. $30.9 million.

The purchase of natural gas by the Liberty Utilities (Central) region is a significant revenue driver and component of operating expenses but these costs are effectively passed through to its customers. As a result, the division compares 'net utility sales' (see non-GAAP Financial Measures) as a more appropriate measure of the division's results. For the twelve months

ended December 31, 2013, net utility sales from natural gas sales and distribution for the Liberty Utilities (Central) region totalled U.S. $49.6 million as compared to U.S. $21.3 million during the same period in 2012, an increase of U.S. $28.3 million. The increase in net utility sales is primarily due to the division reporting a full year of results in 2013 compared to partial year results in the previous year.

For the twelve months ended December 31, 2013 , operating expenses, excluding natural gas purchases, totalled U.S. $26.6 million, as compared to U.S. $13.1 million during the same period in 2012. The increase in operating expenses can be primarily attributed to the addition of the natural gas distribution assets on August 1, 2012 and the Pine Bluff Water System acquired on February 1, 2013.

For the twelve months ended December 31, 2013 , the Liberty Utilities (Central) region's operating profit was U.S. $23.4 million as compared to U.S. $8.2 million in the same period in 2012, an increase of U.S. $15.2 million primarily attributed to the aforementioned acquisitions.

Measured in Canadian dollars, the Liberty Utilities (Central) region's operating profit was $24.1 million as compared to $8.2 million in the same period in 2012.

	Three months ended December 31,	
	2013	2012
Average Active Natural Gas Connections For The Period		
Residential	70,300	72,000
Commercial and Industrial	9,100	9,600
Total Average Active Natural Gas Connections For The Period	**79,400**	**81,600**
Average Active Water Connections For The Period		
Wastewater connections	6,000	5,800
Water distribution connections	21,800	5,300
Total Average Active Water Connections For The Period	**27,800**	**11,100**
Customer Usage (MMBTU)		
Residential	1,308,000	1,160,000
Commercial and Industrial	1,147,000	841,000
Total Customer Usage (MMBTU)	**2,455,000**	**2,001,000**
Gallons Provided		
Wastewater treated (millions of gallons)	88.5	94.6
Water sold (millions of gallons)	803.6	97.3
Total Gallons Provided	**892.1**	**191.9**

The Liberty Utilities (Central) region acquired the Pine Bluff Water System water distribution utility on February 1, 2013, and accordingly, there are no results for this utility for the corresponding period in 2012.

For the three months ended December 31, 2013 , the Liberty Utilities (Central) region natural gas distribution sales totalled 2,455,000 MMBTU as compared to 2,001,000 during the same period in 2012, an increase of 454,000 MMBTU or 22.7%.

During the three months ended December 31, 2013 , the Liberty Utilities (Central) region provided approximately 803.6 million gallons of water to its customers, and treated approximately 88.5 million gallons of wastewater, as compared to 97.3 million gallons of water and 94.6 million gallons of wastewater during the same period in 2012.

As a result of the acquisition of the Pine Bluff Water System on February 1, 2013 the number of water connections in the region increased by 17,700. During the three months ended December 31, 2013 , the amount of water sold also correspondingly increased by 698 million gallons.

	Three months ended December 31,		Three months ended December 31,	
	2013 U.S. $ (millions)	2012 U.S. $ (millions)	**2013 Can $ (millions)**	2012 Can $ (millions)
Revenue				
Utility natural gas sales and distribution	**$ 22.5**	$ 19.7	**$ 23.8**	$ 19.6
Wastewater treatment	**1.5**	1.4	**1.5**	1.6
Water distribution	**3.1**	0.6	**3.2**	0.5
Gas Transportation	0.9	0.8	0.9	0.8
	28.0	22.5	**29.4**	22.5
Less:				
Cost of Sales – Natural Gas	**(14.2)**	(12.0)	**(15.2)**	(11.9)
Net utility sales	13.8	10.5	14.2	10.6
Expenses				
Operating expenses	**(7.2)**	(6.3)	**(7.6)**	(6.3)
Other income	**0.2**	—	**0.2**	—
Division operating profit	**$ 6.8**	$ 4.2	**$ 6.8**	$ 4.3

2013 Fourth Quarter Operating Results

For the three months ended December 31, 2013 , the Liberty Utilities (Central) region's revenue totalled U.S. $28.0 million as compared to U.S. $22.5 million during the same period in 2012, an increase of U.S. $5.5 million. The increase in revenue can be primarily attributed to the addition of the Pine Bluff Water System on February 1, 2013 and the increased natural gas sales and distribution discussed below.

For the three months ended December 31, 2013 , the Liberty Utilities (Central) region's revenue from natural gas sales and distribution totalled U.S. $22.5 million as compared to U.S. $19.7 million during the same period in 2012, an increase of U.S. $2.8 million or 14.2%.

For the three months ended December 31, 2013 , the Liberty Utilities (Central) region's revenue from gas transportation sales totalled U.S. $0.9 million as compared to U.S. $0.8 million during the same period in 2012, an increase of U.S. $0.1 million.

For the three months ended December 31, 2013 , revenue from wastewater treatment and water distribution totalled U.S. $1.5 million and $3.1 million , as compared to U.S. $1.4 million and $0.6 million during the same period in 2012. The increase in total wastewater treatment and water distribution revenue can be primarily attributed to the addition of the Pine Bluff Water System.

For the three months ended December 31, 2013 natural gas purchases for the Liberty Utilities (Central) region's natural gas utility totalled U.S $14.2 million, as compared with U.S. $12.0 million for the same period in 2012, an increase of $2.2 million.

The purchase of natural gas by the Liberty Utilities (Central) region is a significant revenue driver and component of operating expenses but these costs are effectively passed through to its customers. As a result, the division compares 'net utility sales' (utility sales after commodity costs) as a more appropriate measure of the division's results. For the three months ended December 31, 2013 , net utility sales from natural gas sales and distribution for the Liberty Utilities (Central) region totalled U.S. $13.8 million as compared to U.S. $10.5 million during the same period in 2012, an increase of U.S. $3.3 million, or 31.4%.

For the three months ended December 31, 2013 , operating expenses, excluding natural gas purchases, totalled U.S. $7.2 million, as compared to U.S. $6.3 million during the same period in 2012. The increase in operating expenses is primarily attributed to the acquisition of the Pine Bluff Water System on February 1, 2013.

For the three months ended December 31, 2013 , the Liberty Utilities (Central) region's operating profit was U.S. $6.8 million as compared to U.S. $4.2 million in the same period in 2012, an increase of U.S. $2.6 million.

Measured in Canadian dollars, the Liberty Utilities (Central) region's operating profit was $6.8 million as compared to $4.3 million in the same period in 2012.

Liberty Utilities East Region:

	Year ended December 31,	
	2013	2012
Average Active Natural Gas Connections		
Residential	178,800	74,000
Commercial and Industrial	17,200	8,800
Total Average Active Natural Gas Connections	**196,000**	**82,800**
Average Active Electric Connections		
Residential	36,800	36,200
Commercial and Industrial	6,500	6,500
Total Average Active Electric Connections	**43,300**	**42,700**
Customer Usage (GW-hrs)		
Residential	304.6	151.5
Commercial and Industrial	628.4	323.1
Total Customer Usage (GW-hrs) [3]	**933.0**	**474.6**
Customer Usage (MMBTU)		
Residential	7,214,000	1,552,000
Commercial and Industrial	5,666,000	988,000
Total Customer Usage (MMBTU) [1,2,3]	**12,880,000**	**2,540,000**

[1] New England Gas System was acquired on December 20, 2013

[2] Peach State Gas System was acquired on April 1, 2013.

[3] Granite State Electric System and EnergyNorth Gas System were acquired on July 3, 2012.

The Liberty Utilities (East) region is comprised of Liberty Utilities' operations in New Hampshire, Massachusetts and Georgia. The Liberty Utilities (East) region acquired its natural gas distribution system in Massachusetts on December 20, 2013, its natural gas distribution system in Georgia on April 1, 2013, and the New Hampshire natural gas and electric distribution systems on July 3, 2012; accordingly the twelve month results for 2012 are not comparative.

For the twelve months ended December 31, 2013 , the Liberty Utilities (East) region's electricity usage totalled 933.0 GW-hrs and natural gas usage totalled 12,880,000 MMBTU. The Peach State Gas System usage totalled 3,369,000 MMBTU, while the New England Gas System usage totalled 242,000 MMBTU.

As a result of the acquisition of the New England Gas System and the Peach State Gas Systems, the Liberty Utilities (East) region added approximately 115,000 total natural gas connections.

	Year ended December 31,		Year ended December 31,	
	2013 U.S. $ (millions)	2012 U.S. $ (millions)	**2013 Can $ (millions)**	2012 Can $ (millions)
Electricity Assets for regulatory purposes	**101.1**	88.4		
Natural Gas for regulatory purposes	**513.4**	263.4		
Revenue				
Utility electricity sales and distribution [1]	**$ 85.7**	$ 36.8	**$ 88.3**	$ 36.7
Utility natural gas sales and distribution [2,3,4]	**164.1**	45.7	**169.1**	45.3
Gas Transportation	**13.4**	4.6	**13.7**	4.6
Other Revenue	**—**	0.1	**—**	0.1
	$ 263.2	$ 87.2	**$ 271.1**	$ 86.7
Less:				
Cost of Sales – Electricity [1]	**(55.9)**	(24.4)	**(57.6)**	(24.3)
Cost of Sales – Natural Gas [2,3,4,5]	**(99.8)**	(24.0)	**(102.8)**	(23.8)
Net Utility Sales	**$ 107.5**	$ 38.8	**$ 110.7**	$ 38.6
Expenses				
Operating expenses	**(65.3)**	(30.4)	**(67.3)**	(30.2)
Other Income	**1.4**	0.4	**1.5**	0.5
Division operating profit	**$ 43.6**	$ 8.8	**$ 44.9**	$ 8.9

[1] Represents Granite State Electric System revenue and electricity costs since July 3, 2012 acquisition date.

[2] Represents New England Gas System revenue and gas costs since December 20, 2013 acquisition date.

[3] Represents Peach State Gas System revenue and gas costs since April 1, 2013 acquisition date.

[4] Represents EnergyNorth Gas System revenue and costs since July 3, 2012 acquisition date.

[5] Natural Gas costs are shown net of U.S. $11.7 million regulatory authorized deferral related to an under recovery of actual gas costs.

2013 Annual Operating Results

The Liberty Utilities (East) region has investments in electricity assets for regulatory purposes of U.S. $101.1 million, and natural gas assets for regulatory purposes of U.S. $513.4 million as at December 31, 2013, as compared to U.S $88.4 million and U.S. $263.4 million, respectively, as at December 31, 2012. The increase in electricity assets is primarily a result of the construction of a new substation, substation asset upgrades, and the construction of a new supply line by the Granite State Electric System, while the increase in gas assets for regulatory purposes from December 31, 2013 is primarily a result of maintenance and installation of new pipelines at the EnergyNorth Gas System, and the acquisitions of the Peach State and the New England Gas Systems.

For the twelve months ended December 31, 2013 , the Liberty Utilities (East) region's revenue totalled U.S. $263.2 million as compared to U.S. $87.2 million during the same period in 2012.

For the twelve months ended December 31, 2013 , the Liberty Utilities (East) region's revenue from utility electricity sales totalled U.S. $85.7 million.

For the twelve months ended December 31, 2013 , the Liberty Utilities (East) region's revenue from natural gas sales and distribution totalled U.S. $164.1 million, of which the EnergyNorth Gas System contributed U.S $126.0 million, the Peach State Gas System contributed U.S. $35.1 million, and the newly acquired New England Gas System contributed $3.0 million.

For the twelve months ended December 31, 2013 , the Liberty Utilities (East) region's revenue from gas transportation sales totalled U.S. $13.4 million. For the twelve months ended December 31, 2013 , the EnergyNorth Gas System contributed U.S. $11.6 million, the Peach State Gas System contributed U.S.$1.3 million, and the newly acquired New England Gas System contributed U.S. $0.5 million.

For the twelve months ended December 31, 2013 , electricity purchases for the Liberty Utilities (East) region totalled U.S. $55.9 million, and natural gas purchases totalled U.S. $99.8 million.

The cost of electricity and natural gas is passed through to the Liberty Utilities (East) region's customers in the rates they are charged. As a result, the division compares 'net utility sales' (see non-GAAP Financial Measures) as a more appropriate measure of the division's results. For the twelve months ended December 31, 2013 , net utility sales totalled U.S. $107.5 million compared to U.S. $38.8 million during the same period in 2012, an increase of $68.7 million. The increase is due to the fact that the division is reporting a full year of results in 2013 compared to partial year results in the previous year and the impact of the interim annual rate increase approved by the NHPUC on June 27, 2013.

For the twelve months ended December 31, 2013 , operating expenses, excluding electricity and natural gas purchases, totalled U.S. $65.3 million. For the twelve months ended December 31, 2013 , other income for the Liberty Utilities (East) region totaled U.S. $1.4 million, and primarily consists of an equity allowance for funds utilized during construction and rental income. For the twelve months ended December 31, 2013, the Liberty Utilities (East) region's operating profit totalled U.S. $43.6 million.

Measured in Canadian dollars, the Liberty Utilities (East) region's operating profit was $44.9 million.

	Three months ended December 31,	
	2013	2012
Average Active Natural Gas Connections For The Period		
Residential	178,900	73,300
Commercial and Industrial	17,100	8,700
Total Customer Usage (GW-hrs)	**196,000**	**82,000**
Average Active Electric Connections For The Period		
Residential	36,600	36,600
Commercial and Industrial	6,500	6,500
Total Average Active Electric Connections For The Period	**43,100**	**43,100**
Customer Usage (GW-hrs)		
Residential	69.4	68.5
Commercial and Industrial	145.3	143.6
Total Customer Usage (GW-hrs)	**214.7**	**212.1**
Customer Usage (MMBTU)		
Residential	2,068,000	1,199,000
Commercial and Industrial	2,147,000	745,000
Total Customer Usage (MMBTU)	**4,215,000**	**1,944,000**

For the three months ended December 31, 2013 , the Liberty Utilities (East) region's electricity usage totalled 214.7 GW-hrs and natural gas usage totalled 4,215,000 MMBTU as compared to 212.1 GW-hrs and 1,944,000 MMBTU during the same period in 2012. The Peach State Gas System usage totalled 1,394,000 MMBTU, while the New England Gas System usage totalled 242,000 MMBTU.

	Three months ended December 31,		Three months ended December 31,	
	2013 U.S. $ (millions)	2012 U.S. $ (millions)	**2013 Can $ (millions)**	2012 Can $ (millions)
Revenue				
Utility electricity sales and distribution	**$ 22.2**	$ 17.7	**$ 23.3**	$ 17.6
Utility natural gas sales and distribution [1,2]	**62.4**	35.3	**65.7**	34.9
Gas Transportation	**3.5**	2.8	**3.7**	2.8
Other Revenue	**—**	—	**—**	—
	$ 88.1	$ 55.8	**$ 92.7**	$ 55.3
Less:				
Cost of Sales – Electricity	**(14.7)**	(12.3)	**(15.5)**	(12.2)
Cost of Sales – Natural Gas [1,2,3]	**(39.8)**	(21.9)	**(41.9)**	(21.7)
Net Utility Sales	**$ 33.6**	$ 21.6	**$ 35.3**	$ 21.4
Expenses				
Operating expenses	**(18.2)**	(16.5)	**(19.1)**	(16.3)
Other income	**0.3**	0.4	**0.4**	0.4
Division operating profit	**$ 15.7**	$ 5.5	**$ 16.6**	$ 5.5

[1] Represents New England Gas System revenue and gas costs since December 20, 2013 acquisition date.

[2] Represents Peach State Gas System revenue and gas costs since April 1, 2013 acquisition date.

[3] Natural Gas costs are shown net of U.S. $2.5 million regulatory authorized deferral related to an under recovery of actual gas costs.

2013 Fourth Quarter Operating Results

For the three months ended December 31, 2013 , the Liberty Utilities (East) region's revenue totalled U.S. $88.1 million, as compared to U.S. $55.8 million during the same period in 2012, an increase of U.S. $32.3 million, or 57.9%. The increase in revenue can be primarily attributed to the acquisition of the Peach State Gas System on April 1, 2013 and the New England Gas System on December 20, 2013.

For the three months ended December 31, 2013 , the Liberty Utilities (East) region's revenue from utility electricity sales totalled U.S. $22.2 million as compared to U.S. $17.7 million during the same period in 2012, an increase of $4.5 million, or 25.4%, primarily due to interim rates in place at the Granite State Electric System effective July 1, 2013.

For the three months ended December 31, 2013 , the Liberty Utilities (East) region's revenue from natural gas sales and distribution totalled U.S. $62.4 million as compared to U.S. $35.3 million during the same period in 2012, an increase of U.S. $27.1 million, or 76.8%. During the three months ended December 31, 2013, the EnergyNorth Gas System contributed U.S. $43.4 million, while the Peach State Gas System contributed U.S.$16.0 million, and the newly acquired the New England Gas System contributed U.S. $3.0 million.

For the three months ended December 31, 2013 , the Liberty Utilities (East) region's revenue from gas transportation sales totalled U.S. $3.5 million as compared to U.S. $2.8 million during the same period in 2012, an increase of U.S. $0.7 million, or 25.0%. During the three months ended December 31, 2013 the EnergyNorth Gas System contributed U.S. $2.6 million, the Peach State Gas System contributed U.S. $0.4 million, and the newly acquired New England Gas System contributed U.S. $0.5 million.

For the three months ended December 31, 2013 , electricity purchases for the Liberty Utilities (East) region totalled U.S. $14.7 million, and natural gas purchases totalled U.S. $39.8 million as compared to U.S. $12.3 million and U.S. $21.9 million, respectively, during the same period in 2012. The overall electricity purchase expense increase of U.S $2.4 million was primarily the result of an 18% increase in weighted average electricity rates as compared to the same period in 2013 and a 1% increase in the volume of electricity purchased to meet customer demand. The overall natural gas purchases increases

can be primarily attributed to the acquisition of the Peach State Gas System on April 1, 2013 and the New England Gas System on December 20, 2013.

The cost of electricity and natural gas is passed through to the Liberty Utilities (East) region's customers. As a result, the division compares 'net utility sales' (see non-GAAP Financial Measures) as a more appropriate measure of the division's results. For the three months ended December 31, 2013, net utility sales for the Liberty Utilities (East) region totalled U.S. $33.6 million as compared to U.S. $21.6 million during the same period in 2012, an increase of U.S.$12.0 million, or 55.6%, primarily due to an interim annual rate increase approved by the NHPUC on June 27, 2013 and higher customer counts, due to the acquisition of the Peach State Gas System on April 1, 2013 and the New England Gas System on December 20, 2013.

For the three months ended December 31, 2013 , operating expenses, excluding electricity and natural gas purchases, totalled U.S. $18.2 million as compared to U.S. $16.5 million during the same period in 2012, an increase of U.S. $1.7 million, or 10.3%. The increase in operating expenses as compared to the same period in 2012 can be primarily attributed to the acquisition of the Peach State Gas System on April 1, 2013 and the New England Gas System on December 20, 2013.

For the three months ended December 31, 2013 , other income for the Liberty Utilities (East) region totaled U.S. $0.3 million, and primarily consists of an equity allowance for funds utilized during construction and rental income.

For the three months ended December 31, 2013 , the Liberty Utilities (East) region's operating profit totalled U.S. $15.7 million as compared to U.S. $5.5 million during the same period in 2012, an increase of U.S. $10.2 million. The increase in operating profit as compared to the same period in 2012 can be primarily attributed to the acquisition of the Peach State Gas System on April 1, 2013, and the New England Gas System on December 20, 2013.

Measured in Canadian dollars, the Liberty Utilities (East) region's operating profit was $16.6 million as compared to $5.5 million during the same period in 2012, an increase of $11.1 million.

Regulatory Proceedings

The following table summarizes the major regulatory proceedings within Liberty utilities currently underway:

Utility	State	Regulatory Proceeding Type	Rate Request (U.S. $000's)	Current Status
Rio Rico Water System	Arizona	General Rate Case	$750	Order issued authorizing $420 annual increase
LPSCo Water System	Arizona	General Rate Case	$3,000	Order expected first half of 2014
Peach State Gas System	Georgia	Georgia Rate Adjustment Mechanism ("GRAM") filing	$4,900	Settlement reached. Final Commission approval expected by the end of Q1 2014.
EnergyNorth Gas System	New Hampshire	Rate Proceeding	Cast iron/bare steel replacement program increase of $200	Order approving $200 increase for one year
Granite State Electric System	New Hampshire	General Rate Case	$13,000 + $1,200 step adjustment in 2014	Settlement reached for $10,200 + $1,100 in step increase for 2014. Commission approval expected by the end of Q1 2014
Missouri Gas System	Missouri	General Rate Case	$6,300	Order expected first quarter of 2015

On May 31, 2012, the Liberty Utilities (West) region 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.

On February 28, 2013, LPSCo Water System filed a general rate case with the Arizona Corporation Commission related to the LPSCo Water System seeking, among other things, an increase in EBITDA by U.S. $3.0 million over the 2012 results if approved as filed. The application seeks recognition of increased capital investment and increased operating expenses over current rates. In addition to a revenue increase, the application seeks 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. New rates are expected to be implemented in the first half of 2014.

On October 30, 2013, the Peach State Gas System filed an application to increase rates by U.S. $4.9 million in its annual Georgia Revenue Adjustment Mechanism (“GRAM”) filing with the Georgia Public Service Commission (“GPSC”). In January 2014, Liberty Utilities and the Staff of the GPSC agreed to a settlement which will provide an annual revenue increase of U.S. $4.7 million. It is anticipated that this settlement will be approved in March 2014.

On May 15, 2013, the Liberty Utilities (East) region 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.

On March 29, 2013, the Granite State Electric System filed a rate case with the 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. The filing is based on a 2012 test year, with revenues and expenses adjusted to reflect known and measurable changes. Among other things, the Granite State Electric System requested and received approval to continue the current cost-recovery tracking mechanism related to the Reliability Enhancement and Vegetation Management Plan and was granted an annual rate increase of U.S. $0.4 million starting July 1, 2013. The Granite State Electric System also requested a modification to allow for recovery of pre-staging personnel and equipment for qualifying storms. On June 27, 2013, the NHPUC approved a settlement agreement authorizing a temporary annual rate increase of U.S.$6.5 million effective July 1, 2013, and provides recognition for Liberty to request an increase to its storm recovery adjustment factor (“SRAF”). On January 22, 2014, the Granite State Electric System entered a settlement with the New Hampshire PUC Staff, which will provide for a rate increase of U.S.$10.9 million consisting of U.S. $9.8 million in base rates and an additional U.S. $1.1 million for incremental capital expended after the test year. In addition, the settlement allows for one time recovery of rate case expenses of U.S. $0.4 million. It is anticipated that the settlement will be approved in the first quarter of 2014.

On July 2, 2013, the Missouri Gas System filed an application with the Missouri Public Service Commission (“MPSC”) seeking accelerated recovery for infrastructure deployed under the utility’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.

In the first quarter of 2014, the Midstates Gas System filed a rate case with the Missouri Public Service Commission ("MOPSC") seeking an increase in EBITDA of U.S. $6.3 million. 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 is expected to conclude in first quarter of 2015.

APUC: Corporate and Other Expenses

	Three months ended December 31,		Year ended December 31,	
	2013 (millions)	2012 (millions)	**2013 (millions)**	**2012** (millions)
Corporate and other expenses:				
Administrative expenses	**$ 5.2**	$ 5.3	**$ 23.5**	$ 19.6
(Gain)/Loss on foreign exchange	**(0.1)**	(1.6)	**(0.6)**	(0.6)
Interest expense	**14.4**	11.1	**53.3**	35.6
Interest, dividend and other Income	**0.7**	0.4	**2.5**	2.1
Write down of long lived assets	**—**	—	**—**	—
Acquisition-related costs	**0.6**	1.3	**2.1**	7.7
(Gain)/Loss on derivative financial instruments	**(2.7)**	(0.4)	**(5.2)**	(0.2)
Income tax expense/(recovery)	**5.2**	(6.5)	**9.2**	(14.4)

2013 Annual Corporate and Other Expenses

During the year ended December 31, 2013, administrative expenses totalled $23.5 million, as compared to $19.6 million in the same period in 2012. The expense increase in the year ended December 31, 2013 primarily results from additional personnel, increased wages, additional costs required to administer APUC’s operations, share based compensation expense and other costs as compared to the same period in 2012.

For the year ended December 31, 2013, interest expense totalled $53.3 million as compared to $35.6 million in the same period in 2012. The increased interest expense is a result of new indebtedness incurred during the second half of 2012 and the first quarter of 2013 used to partially finance the new acquisitions and fund other growth initiatives. These amounts were partially offset by $4.9 million in reduced interest expense related to the Series 3 convertible debentures and $1.7 million in 2012 related to the Quebec water lease litigation.

For the year ended December 31, 2013, interest, dividend and other income totalled $2.5 million as compared to $2.1 million in the same period in 2012. Interest, dividend and other income primarily consists of dividends from APUC's share investment in the Kirkland and Cochrane facilities.

For the year ended December 31, 2013, acquisition related costs totalled $2.1 million as compared to $7.7 million in the same period in 2012. 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, 2013, gains on derivative financial instruments totalled $5.2 million as compared to $0.2 million in the same period in 2012. The increase was primarily driven by derivative gains on the AES market hedges due to increased market prices during 2013 as compared to the same period in 2012.

An income tax expense of $9.2 million was recorded in the year ended December 31, 2013, as compared to a recovery of $14.4 million during the same period in 2012. The increase income tax expense for the year ended December 31, 2013 is primarily due to higher earnings in the U.S. resulting from the various U.S. acquisitions completed in 2012, deferred taxes on HLBV income, the recognition of deferred credits from the utilization of deferred income tax assets recognized at the time of the Unit Exchange Offer, non-taxable inter-corporate dividends, and other items permanently non-deductible for tax purposes.

2013 Fourth Quarter Corporate and Other Expenses

During the quarter ended December 31, 2013, administrative expenses totalled $5.2 million, as compared to $5.3 million in the same period in 2012.

For the quarter ended December 31, 2013, interest expense totalled $14.4 million as compared to $11.1 million in the same period in 2012. The increased interest expense is a result of new indebtedness incurred during the first half of 2013 used to partially finance the new acquisitions and fund other growth initiatives. These amounts were partially offset by reduced interest expense related to convertible debentures due to the conversion of the Series 3 Debentures in the prior year.

For the quarter ended December 31, 2013, interest, dividend and other income totalled $0.7 million, as compared to $0.4 million in the same period in 2012. Interest, dividend and other income primarily consists of dividends from APUC's share investment in the Kirkland and Cochrane facilities.

For the quarter ended December 31, 2013, gains on derivative financial instruments totalled $2.7 million, as compared to $0.4 million in the same period in 2012. The increase was primarily driven by derivative gains on the AES market hedges due to increased market prices during 2013 as compared to the same period in 2012.

An income tax expense of $5.2 million was recorded in the three months ended December 31, 2013, as compared to a recovery of $6.5 million during the same period in 2012. The income tax expense for the three months ended December 31, 2013 primarily due to deferred taxes on HLBV income, the recognition of deferred credits from the utilization of deferred income tax assets recognized at the time of the Unit Exchange Offer, non-taxable inter-corporate dividends, and other items permanently non-deductible for tax purposes.

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,	
	2013 (millions)	2012 (millions)	**2013 (millions)**	2012 (millions)
Net earnings attributable to Shareholders	$ 13.1	$ 6.4	$ 20.3	$ 14.5
Add (deduct):				
Net earnings / (loss) attributable to the non-controlling interest, exclusive of HLBV	**3.4**	(3.2)	**9.6**	(3.3)
(Earnings) / loss from discontinued operations	**6.7**	0.4	**42.0**	(1.0)
Income tax expense / (recovery)	**5.2**	(6.5)	**9.2**	(14.4)
Interest expense	**14.4**	11.1	**53.3**	35.6
Acquisition costs	**0.6**	1.3	**2.1**	7.7
Quebec water lease litigation	**—**	—	**—**	0.5
(Gain)/Loss on derivative financial instruments	**(2.7)**	(0.4)	**(5.2)**	(0.2)
(Gain)/Loss on foreign exchange	**(0.1)**	(1.6)	**(0.6)**	(0.6)
Depreciation and amortization	**27.0**	16.5	**96.2**	49.3
Adjusted EBITDA	**$ 67.6**	$ 24.0	**$ 226.9**	$ 88.1

Hypothetical Liquidation at Book Value ("HLBV") represents the value of net tax attributes earned by APCo 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, 2013 amounted to approximately $6.8 million and $20.4 million, respectively.

For the year ended December 31, 2013, Adjusted EBITDA totalled $226.9 million as compared to $88.1 million during the same period in 2012, an increase of $138.8 million. For the quarter ended December 31, 2013, Adjusted EBITDA totalled $67.6 million as compared to $24.0 million, an increase of $43.6 million compared to the same period in 2012.

The major factors impacting Adjusted EBITDA are set out below. A more detailed analysis of these factors is presented within the business unit analysis.

	Three months ended December 31 (millions)	Year ended December 31 (millions)
Comparative Prior Period Adjusted EBITDA	$ 24.0	$ 88.1
Significant Changes:		
Liberty Utilities:		
Increased demand and rate decoupling at the CalPeco Electric System	0.8	9.3
Acquisitions	12.8	48.5
APCo:		
Renewable		
Increased hydrology resource	0.8	6.6
Acquisitions of the U.S. Wind Facilities	23.6	62.9
Sale of Renewable Energy Credits	2.2	5.7
Increased wind resources at the St Leon wind facilities	1.0	1.3
Increased demand for retail sales at AES	—	2.6
Thermal		
Windsor Locks & Sanger Facilities - Increased energy sales	0.3	2.5
Administrative expense	0.2	(3.9)
Increased/(decreased) results from the stronger U.S. dollar	4.3	5.0
Other	(2.4)	(1.7)
Current Period Adjusted EBITDA	$ 67.6	$ 226.9

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,	
	2013 (millions)	2012 (millions)	**2013 (millions)**	2012 (millions)
Net earnings attributable to Shareholders	**$ 13.1**	$ 6.4	**$ 20.3**	$ 14.5
Add (deduct):				
(Gain) / Loss from discontinued operations, net of tax	**6.7**	0.4	**42.0**	(1.0)
(Gain)/Loss on derivative financial instruments, net of tax	**(1.6)**	(0.2)	**(2.7)**	(0.2)
Cross Currency Interest Rate Swap interest differential	**—**	—	**0.3**	—
Quebec water lease litigation and interest, net of tax	**—**	—	**—**	1.2
(Gain)/Loss on foreign exchange, net of tax	**(0.1)**	(0.9)	**(0.3)**	(0.3)
Acquisition costs, net of tax	**0.4**	0.8	**1.3**	4.7
Adjusted net earnings	**$ 18.5**	$ 6.5	**$ 60.9**	$ 18.9
Adjusted net earnings per share	**$ 0.08**	$ 0.03	**$ 0.27**	$ 0.11

For the year ended December 31, 2013, adjusted net earnings totalled $60.9 million as compared to adjusted net earnings of $18.9 million, an increase of $42.0 million as compared to the same period in 2012. The increase in adjusted net earnings

for the year ended December 31, 2013 is primarily due to higher income from operations, decreased acquisition costs partially offset by higher interest expense, and depreciation and amortization expense as compared to the same period in 2012.

For the three months ended December 31, 2013 , adjusted net earnings totalled $18.5 million as compared to adjusted net earnings of $6.5 million, an increase of $12.0 million as compared to the same period in 2012. The increase in adjusted net earnings for the three months ended December 31, 2013 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 2012.

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,	
	2013 (millions)	2012 (millions)	**2013 (millions)**	2012 (millions)
Cash flows from operating activities	**$ 31.3**	$ 17.1	**$ 98.9**	$ 63.0
Add (deduct):				
Changes in non-cash operating items	**13.5**	7.2	**47.8**	3.9
Cash (provided)/used in discontinued operation	**0.5**	(1.0)	**4.4**	(7.8)
Cross Currency Swap interest difference	**—**	—	**0.3**	—
Acquisition costs	**0.6**	1.3	**2.1**	7.7
Adjusted funds from operations	**$ 45.9**	$ 24.6	**$ 153.5**	$ 66.8
Adjusted funds from operations per share	**0.22**	**0.14**	**0.72**	0.42

For the year ended December 31, 2013, adjusted funds from operations totalled $153.5 million as compared to adjusted funds from operations of $66.8 million, an increase of $86.7 million as compared to the same period in 2012.

For the three months ended December 31, 2013 , adjusted funds from operations totalled $45.9 million as compared to adjusted funds from operations of $24.6 million, an increase of $21.3 million as compared to the same period in 2012.

Summary of Property, Plant and Equipment Expenditures

	Three months ended December 31,		Year ended December 31,	
	2013 (millions)	2012 (millions)	**2013 (millions)**	2012 (millions)
APCo:				
Renewable	**$ 18.0**	$ 7.5	**$ 46.9**	$ 21.1
Thermal	**1.3**	(2.0)	**2.6**	10.3
Total APCo	**$ 19.3**	$ 5.5	**$ 49.5**	$ 31.4
LIBERTY UTILITIES				
West	**13.4**	9.6	**23.7**	23.2
Central	**8.4**	8.8	**28.6**	10.8
East	**21.6**	8.9	**56.6**	12.5
Total Liberty Utilities	**$ 43.4**	$ 27.3	**$ 108.9**	$ 46.5
Corporate	**—**	0.1	**—**	—
Total	**$ 62.7**	$ 32.9	**$ 158.4**	$ 77.9

The company's consolidated capital expenditure plan for 2014 is approximately $460.0 million. APCo expects to invest approximately $260.0 million primarily in connection with the development of its existing project pipeline. Liberty Utilities expects to invest approximately $200.0 million primarily to improve the reliability and efficiency of its gas, and electric utility distribution systems.

APUC anticipates that it can generate sufficient liquidity through internally generated operating cash flows, bank credit facilities as well as the debt and equity capital markets to finance its property, plant and equipment expenditures and other commitments.

2013 Annual Property Plant and Equipment Expenditures

During the twelve months ended December 31, 2013 , APCo incurred capital expenditures of $49.5 million, as compared to $31.4 million during the comparable period in 2012,

During the twelve months ended December 31, 2013 , APCo's Renewable Energy Division spent $46.9 million in capital expenditures as compared to $21.1 million in the comparable period in 2012. The capital expenditures primarily relate to project costs for the Cornwall Solar, Chaplin and St Damase development projects, as well as major repairs and upgrades at the Long Sault and Tinker Hydro Facilities. APCo's Thermal Energy Division net capital expenditures were $2.6 million, as compared to $10.3 million in the comparable period in 2012. The capital expenditures in the prior year were primarily related to the Windsor Locks repowering and the major maintenance at the Sanger Thermal Facility offset by two one-time, non-recurring items received by the Windsor Locks Thermal Facility: the $6.5 million grant from the State of Connecticut; and a $2.4 million heat and power ITC sponsored by the U.S. Federal Government.

During the twelve months ended December 31, 2013 , Liberty Utilities invested $108.9 million in capital expenditures as compared to $46.5 million during the comparable period in 2012. The Liberty Utilities (West) region's $23.7 million investment in capital expenditures was primarily related to growth and upgrades at the CalPeco Electric System and the expansion of the LPSCo Water System. The Liberty Utility (Central) region's $28.6 million investment in capital expenditures was primarily related to pipe expansion and replacement activities, IT system implementations, and the construction of a new building, as a result of the Midstate Gas Systems acquisition. The Liberty Utility (East) region's $56.6 million investment in capital expenditures reflected the installation of a new substation, the start of a second supply line, the completion of certain substation upgrades and reliability enhancement projects on the Granite State Electric System, the installation of new mains and services supporting growth and distribution main replacements and reinforcements on the EnergyNorth Gas system, and system updates at the Peach State Gas System.

2013 Fourth Quarter Property Plant and Equipment Expenditures

During the three months ended December 31, 2013 , APCo incurred capital expenditures of $19.3 million, as compared to $5.5 million during the comparable period in 2012. During the three months ended December 31, 2013 , APCo's Renewable Energy Division spent $18.0 million in capital expenditures as compared to $7.5 million in the comparable period in 2012. The capital expenditures primarily relate to Cornwall Solar and St. Damase development proejcts, as well as upgrades at the Tinker Hydro Facility. APCo's Thermal Energy Division net capital expenditures were $1.3 million, as compared to capital recovery of $2.0 million in the comparable period in 2012. The 2013 thermal capital expenditures consist of $1.0 relating to Windsor Locks Thermal Facility and $0.3 million relating to Sanger Thermal Facility whereas the prior capital expenditures were $0.4 million relating to Sanger Thermal Facility offset by a $2.4 million ITC sponsored by the U.S. Federal Government related to the repowering of the Windsor Locks Thermal Facility.

During the three months ended December 31, 2013 , Liberty Utilities invested $43.4 million in capital expenditures as compared to $27.3 million during the comparable period in 2012. The Liberty Utilities (West) region's spend was primarily related to growth and upgrades at the CalPeco Electric System and the expansion of the LPSCo Water System. The Liberty Utility (Central) region's $8.4 million investment in capital expenditures was primarily related to pipe expansion and replacement activities and IT system implementations, as a result of the Midstates Gas System acquisition. The Liberty Utility (East) region's $21.6 million investment in capital expenditures was primarily related to a second supply line and reliability enhancement projects on the Granite State Electric System, the installation of new mains and services supporting growth and system reinforcements on the EnergyNorth Gas System, and system updates at the Peach State Gas System.

Quebec Dam Safety Act

As a result of the dam safety legislation passed in Quebec (Bill C93), APCo 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.

APCo currently estimates further capital expenditures of approximately $15.4 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:

	Total	2014	2015	2016	2017
Future Estimated Bill C-93 Capital Expenditures	15.4	1.0	7.3	6.8	0.3

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

APCo completed the majority of the second phase of the on-site remediation work for the Mont Laurier Hydro Facility in 2013 at a capital cost of approximately $0.2 million. The on-site remediation is now substantially complete.

In 2013 APCo completed a risk review of the of the dam rehabilitation plan for the Donnacona Hydro Facility and will explore methods to reduce risk associated with the rehabilitation project in 2014 . The remedial on-site work is anticipated to start in 2015 and be completed in 2016.

The dam safety study and a detailed condition assessment for the St. Alban facility have been completed. A small portion of the on-site remediation associated with the spillway gate superstructure was performed in 2013 at a cost of $0.1 million. APCo anticipates engineering and regulatory review for the remediation of the main dam to be performed in 2014, with remedial work in 2015 to 2016.

APCo is presently reviewing options with respect to the Belleterre Hydro Facility including the removal of several small dams that are not required for power generation. APCo anticipates completion of any required work on these dams by 2017.

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

The dam remediation work related to the Rawdon and Chute Ford Hydro Facilities has been completed.

In addition to the C-93 related dam remediation work, APCo 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 at APUC, APCo and Liberty Utilities 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 subsidiaries as at December 31, 2013 under the Facilities:

	As at December 31, 2013				As at Dec 31 2012
	APUC (millions)	APCo (millions)	Liberty Utilities (millions)	Total (millions)	Total (millions)
Committed Facilities	$ 65.0	$ 200.0	$ 212.7	**$ 477.7**	$ 329.5
Funds drawn on Facilities	—	(124.6)	(85.6)	(210.2)	(54.5)
Letters of Credit issued	(9.9)	(47.7)	(7.3)	(64.9)	(50.7)
Funds available for draws on the Facilities	**$ 55.1**	**$ 27.7**	**$ 119.8**	**$ 202.6**	**$ 224.3**
Cash on Hand				13.8	53.1
Total liquidity and capital reserves				**$ 216.4**	**$ 277.4**

As at December 31, 2013, the APUC Credit Facility, a $65.0 million senior unsecured revolving credit facility, was undrawn and had $9.9 million o outstanding letters of credit.

As at December 31, 2013, the APCo $200.0 million senior unsecured revolving credit facility (the “APCo Facility”) had drawn $124.6 million and had $47.7 million in outstanding letters of credit under the APCo Facility.

As at December 31, 2013, the Liberty Utilities $212.7 million (U.S.$200.0 million) senior unsecured revolving credit facility (the "Liberty Facility") had drawn $85.6 million and had $7.3 million of outstanding letters of credit.

On November 19th, 2013, APUC amended its existing $30.0 million senior unsecured credit facility ("APUC Facility") to increase the commitments available to $65.0 million and extend maturity to November 19, 2016. On January 3rd, 2014 a subsidiary of APUC drew on the APUC Facility to acquire a 100% interest in an office building at an approximate cost of $46.8 million. The building will be approximately 50% occupied by APUC and serve as corporate headquarters with the remainder leased to third parties.

On September 30, 2013, Liberty Utilities increased the credit available under the senior unsecured revolving credit facility (the "Liberty Facility") to U.S. $200.0 million from U.S. $100.0 million. The larger credit facility provides Liberty Utilities with the additional liquidity required resulting from the various acquisitions completed in 2013 and on 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, have improved. The amended facility will now expire on September 30, 2018.

Long Term Debt

On January 1, 2013, in conjunction with the acquisition of the Shady Oaks Wind Facility, APCo assumed a U.S. $150.0 million dollar variable rate long term credit facility. The facility is secured by the assets of the Shady Oaks Wind Facility. In 2013 APCo made principal payments of U.S. $25.0 million in the second quarter and U.S. $3.0 million in the third quarter of 2013 and will be required to make semi-annual principal payments ranging between U.S. $3.0 million and U.S. $6.0 million thereafter. The facility matures in 2026. Funds advanced against the facility are repayable at any time without penalty. Accordingly, subsequent to year end, APCo made a U.S.$ 40.0 million prepayment against the principal balance outstanding.

On March 14, 2013 Liberty Utilities completed a U.S. $15.0 million private placement debt financing. The notes are senior unsecured notes with a 10 year bullet maturity and carry a coupon of 4.14%.

On July 31, 2013, Liberty Utilities issued U.S. $125.0 million of debt through a private placement. The notes are senior unsecured with an average life maturity of approximately ten years and a weighted average coupon of 3.81%.

On December 20, 2013, in connection with the acquisition of New England Gas Company, Liberty Utilities assumed first mortgage bonds of U.S. $6.0 million, bearing an interest rate of 7.24%, maturing December 27, 2027; U.S. $7.0 million, bearing an interest rate of 7.99%, maturing December 26, 2026; and, U.S. $6.5 million, bearing an interest rate of 9.44%, maturing Feb 20, 2020.

Subsequent to year end, on January 17, 2104, APCo issued $200.0 million 4.65% senior unsecured debentures with a maturity date of February 15, 2022 (the "APCo Debentures") pursuant to a private placement in Canada and the United States. The APCo 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, APCo entered into a fixed for fixed cross currency swap, coterminous with the APCo 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%.

As at December 31, 2013 the weighted average tenor of APUC's total long term debt is approximately 8.4 years with an average interest rate of 4.8%

Contractual Obligations

Information concerning contractual obligations as of December 31, 2013 is shown below:

	Total (millions)	Due less than 1 year (millions)	Due 1 to 3 years (millions)	Due 4 to 5 years (millions)	Due after 5 years (millions)
Long-term debt obligations[1]	$ 1,255.6	8.3	147.1	171.9	928.3
Advances in aid of construction	$ 78.9	1.2			77.7
Interest on long-term debt obligations	$ 416.8	54.8	103.6	90.0	168.4
Purchase obligations	$ 156.9	156.9			
Environmental Obligations	$ 77.7	10.1	45.2	3.9	18.5
Derivative financial instruments:					
Cross Currency Swap	$ 7.9	—	—	—	7.9
Interest rate swap	$ 3.1	1.9	1.2	—	—
Energy derivative contracts	$ 4.8	0.2	0.1	—	4.5
Capital lease obligations	$ 4.0	0.1	3.9	—	—
Capital projects	$ 51.6	49.3	2.3	—	—
Long term service agreements	$ 633.2	24.1	53.3	57.5	498.3
Purchased power	$ 111.5	64.6	46.9	—	—
Gas delivery, service and supply agreements	$ 156.1	42.1	40.2	19.3	54.5
Operating leases	$ 106.1	5.1	8.5	7.3	85.2
Other obligations	$ 21.1	7.3	—	—	13.8
Total obligations	$ 3,085.3	$ 426.0	$ 452.3	$ 349.9	$ 1,857.1

Equity

The shares of APUC are publicly traded on the Toronto Stock Exchange (“TSX”). As at December 31, 2013, APUC had 206,348,985 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.

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, 2013, APUC had issued 4,800,000 cumulative rate reset preferred shares, Series A (the “Series A Shares”), yielding 4.5% annually for the initial six-year period ending on December 31, 2018, and 100 Series C preferred shares (the "Series C Shares") that were issued in exchange for 100 Class B limited partnership units issued by St. Leon Wind Energy LP.

APUC has a shareholder dividend reinvestment plan (the “Reinvestment Plan”) for registered holders of shares (“Shareholders”) of APUC. As at December 31, 2013, 43.2 million common shares representing approximately 21% of total shares outstanding had been registered with the Reinvestment Plan and 2,126,258 shares had been issued during the year ended December 31, 2013. During the quarter ended December 31, 2013 688,886 common shares were issued under the Reinvestment Plan, and subsequent to the end of the quarter, on January 15, 2014, an additional 501,818 common shares were issued under the Reinvestment Plan.

Subsequent to the end of the year, 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 million. The shares yield 5.0% annually for the initial five-year period ending on 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 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.

On January 1, 2013, the Company issued 100 redeemable Series C Shares and exchanged such shares for the 100 Class B units that provide dividends identical to what is expected from the Class B units, as determined by independent consultants retained by the Independent Board Committee.

On November 19, 2012, APUC announced its intent to redeem, on January 1, 2013, the convertible unsecured debentures maturing on June 30, 2017 ("Series 3 Debentures") bearing interest at 7.0% per annum. During the year ended December 31, 2012, a principal amount of $61.6 million Series 3 Debentures were converted into 14,669,266 shares of APUC. 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 a face value of $0.96 million Series 3 Debentures outstanding. Subsequent to the end of the quarter, on January 1, 2013, APUC redeemed the outstanding Series 3 Debentures and issued 150,816 shares as a result of the redemption. Following the redemption, there were no Series 3 Debentures outstanding.

Emera subscription receipts

For the year ended December 31, 2013, a total of 15.2 million common shares were issued to Emera for proceeds of $90.5 million pursuant to subscription agreements in contemplation of certain previously announced transactions, as outlined below:

- On February 7, 2013 and February 14, 2013, respectively, in connection with the closing of the acquisition of the Minonk and Senate Wind Facilities from Gamesa USA that occurred on December 10, 2012, APUC issued 2.6 million common shares at a price of $5.74 and 5.2 million shares at a price of $5.74. The total $45 million in cash proceeds from the exercise of the subscription receipts were used to fund a portion of the cost of the acquisition;
- On February 14, 2013, in connection with the acquisition of Emera's non-controlling interest in the CalPeco Electric System, APUC issued 3.4 million common shares at a price of $4.72 for share proceeds of $16.1 million; and
- On March 26, 2013, in connection with the acquisition of the Peach State Gas System, APUC issued 4.0 million shares at a price of $7.40 per share to Emera pursuant to a subscription agreement, for total cash proceeds of $29.3 million. The cash proceeds were used to partially fund the acquisition of the Peach State Gas System.

As at March 6, 2014, in total, Emera owns 50.1 million APUC common shares representing approximately 24.2% of the total outstanding common shares of the Company, and there are no 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, 2013, APUC recorded $570 and $2.0 million (2012 - $287 and $1.8 million) in total share-based compensation expense. 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, 2013, total unrecognized compensation costs related to non-vested options and share unit awards were $1.8 million and $0.1 million respectively, and are expected to be recognized over a period of 1.57 years and 1.0 year 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.

For the year ended December 31, 2013, 816,402 options were granted to senior executives and certain senior management of APUC which allow for the purchase of common shares at a weighted average price of $7.72. One third of the options will vest on each of January 1, 2014, 2015, and 2016.

As at December 31, 2013, APUC had 4,567,129 options issued and outstanding. 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.

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. As APUC does not expect to settle these instruments in cash, these PSUs are accounted for as equity awards.

As at December 31, 2013, a total of 66,195 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.

As at December 31, 2013, a total of 74,786 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. As at December 31, 2013, a total of 146,813 shares had been issued under the ESPP.

MANAGEMENT OF CAPITAL STRUCTURE

APUC views its capital structure in terms of its debt levels, at APCo, Liberty Utilities and an overall company level, and its equity balances.

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 proper credit facilities available for ongoing investment in growth and investment in 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 units are using a capital structure which is appropriate for their respective industries.

RELATED PARTY TRANSACTIONS

Resolution of Business Associations with APMI, Affiliates and Senior Executives

Ian Robertson and Chris Jarratt ("Senior Executives") 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" within this section refers to a Committee comprising the independent members of the Board of Directors of APUC as defined in National Instrument 58-101. 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 fair market valuations of the generating assets, tax and legal matters.

The process initiated in 2011 has been completed and all related party transactions between APUC and the Parties have been resolved 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

As at December 31, 2013, amounts due from related parties were nil (December 31, 2012 - $816) owed to APUC from the Parties and amounts due to related parties were nil (December 31, 2012 - $1,811) owed to the Parties.

Prior to 2010, APMI was the manager of APIF (predecessor organization to APUC) and at the time of the internalization of management, had a number of fees under negotiation as described below:

- APMI was one of the original developers of the Red Lily I Wind Facility and was entitled to a royalty fee based on a percentage of operating revenue and a development fee from the equity owner of the Red Lily I Wind Facility. In 2011, APUC acquired APMI's interest in this royalty.
- As part of the project to re-power the Sanger facility, APUC entered into an agreement with APMI to undertake certain construction management services on the project for a performance based contingency fee.
- During 2007, APUC allowed its offer to acquire Clean Power Income Fund to expire and earned a termination fee for which APMI was entitled to a portion thereof.
- During 2008, APMI provided construction supervision services for the construction of BCI Thermal Facility and was entitled to a construction supervision fee on the BCI projects.
- During 2009, APMI provided management services to APUC for which fees were earned but not paid. In the provision of these management services, APMI incurred and was also entitled to reimbursement of reasonable expenses in 2009 which were not reimbursed by APUC.

Resolution: The Independent Board Committee and the Parties entered into a definitive agreement on November 15, 2013 whereby APUC agree to pay the Parties $1,829 in connection with outstanding fees and the Parties shall pay APUC $812 in connection with reimbursement of expenses both in full satisfaction of the related party balances. The balances have been fully settled as at December 31, 2013.

The aforementioned transaction was completed by December 31, 2013.

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

Prior to December 31, 2013, 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 Hydro Facility is a 4 MW hydroelectric generating facility constructed in 1998 in which APUC owned a 45% interest and Senior Executives held 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 the Long Sault Hydro Facility by way of subscribing to two notes from the original partners. One of the original partners is an affiliate of APMI which was entitled to receive 5% of the equity cash flows commencing in 2014.
- BCI is an energy supply facility which sells steam produced from APCo's EFW Facility . In 2004, APMI acquired 50 Class B partnership units in BCI equal to 50% of the annual returns on the project greater than 15%.

Resolution: As part of the process to resolve the co-ownership issue of the above noted assets, the Independent Board Committee undertook valuations by independent consultants which were reviewed and accepted by the Independent Board Committee. APUC and the Parties entered into an agreement whereby APUC would acquire the Parties' shares of Algonquin Power Corporation Inc. which owns a residual equity interest in the 18MW Long Sault Rapids Hydro Facility and the partnership interest in the BCI Thermal Facility for an amount equal to $3,780. In addition APUC and the Parties entered into an agreement whereby the Parties would acquire APUC's 45% interest in the 4MW Rattle Brook Hydro Facility for an amount equal to $3,408. APUC earned a fee of $400 from APC during the year ended December 31, 2013 (2012 -$nil) related to settlement of the related party transactions.

The aforementioned transaction was completed on December 31, 2013.

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. The Class B units held by Senior Executives received cash distributions of $nil and $14 for the three and twelve months ended December 31, 2013 (2012 - $47 and $175).

Resolution: On January 1, 2013, the Company issued 100 redeemable Series C preferred shares and exchanged such shares for the 100 Class B units 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. Independent tax, legal and accounting advisors were also retained by the Independent Board Committee to provide advice in relation to the exchange.

As of January 1, 2013, no Senior Executives had any further direct or indirect ownership of the St. Leon facility.

Office Facilities

APUC has leased a portion of its head office facilities since 2001 on a triple net basis from an entity partially owned by Senior Executives. The Independent Board Committee conducted independent reviews of the office leasing market and believes the current terms and conditions for office lease are at fair market value for a building of comparable size and quality. Base lease costs for the three and twelve months ended December 31, 2013 were $77 and $310 (2012 - $83 and $333).

Resolution: The current office lease for a portion of its head office facilities expires on December 31, 2015. In August 2013, APUC through a wholly owned subsidiary has acquired a new office facility which is suitable for meeting the future head office needs of APUC. Upon occupancy of the new head office facilities which is anticipated to occur in 2014, it is expected that the currently occupied premises will be subleased to third parties and the relationship between APUC and Senior Executives in respect of office premises will be concluded.

The Board has deemed this related party transaction to have been satisfactorily addressed.

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 interest. In 2004, APUC remitted $1,300 to an affiliate of APMI as an advance against expense reimbursements (including utilization reserves) for APUC's business use of the aircraft. By the end of 2012 the entire advance had been amortized against expense reimbursements and therefore no amortization expense during the three and twelve months ended December 31, 2013 related to the advance were incurred (2012 - $52 and $279). During the three and twelve months ended December 31, 2013 , APUC reimbursed direct costs in connection with the use of the aircraft of $161 and $472 (2012 - $103 and $598).

Resolution: As of December 31, 2013, the remaining amount of the advance was $nil (December 31, 2012 - $nil) and as a result the Independent Board Committee is satisfied that the advance arrangement has concluded. The Independent Board Committee and the Parties have agreed that all future utilization of chartered aircraft will be undertaken through third party charter operators at fair market value and under arrangements in which the Senior Executives have no interest.

The Board has deemed this related party transaction to have been satisfactorily addressed.

Operations Services

APUC provides supervisory services on a cost recovery basis for one small hydro facility hydroelectric generating facility where Senior Executives hold an equity interest. The fees paid in relation to the supervisory management services were nominal for the three and twelve months ended December 31, 2012 and 2013.

Resolution: This agreement terminated on December 31, 2013.

Trafalgar

APCo owns debt on seven hydroelectric facilities owned by Trafalgar Power Inc. and an affiliate ("Trafalgar Hydro Facility"). 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.

Resolution: In 2004, the Board reimbursed APMI $1 million of the total third party legal fees (which to that point totalled $2 million), and APUC would 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.

The Board has deemed this related party transaction to have been satisfactorily addressed.

Other Related Party Transactions

Related Party Transactions between APUC and Emera are discussed in the section below titled *"Transactions with Emera"*.

Transactions with Emera

A member of the Board of Directors of APUC, Chris Huskilson, is an executive at Emera.

In 2011, a subsidiary of Emera provided lead market participant services for fuel capacity and forward reserve markets to ISO NE for the Windsor Locks facility. During the three and twelve months ended December 31, 2013 APUC paid U.S. $nil (2012 - U.S. $nil) in relation to this contract. In 2011, APUC provided a corporate guarantee to a subsidiary of Emera in an amount of U.S. $1,000 in conjunction with this contract.

For the three and twelve months ended December 31, 2013, the Energy Services Business sold electricity to Maine Public Service Company ("MPS"), a subsidiary of Emera, amounting to U.S. $1,453 and U.S. $6,042 (2012 - U.S. $1,539 and U.S. $6,096). 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.

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

Other

An individual related to Ian Robertson, CEO of APUC provided market research consulting services to certain subsidiaries of Liberty Utilities. During the three and twelve months ended December 31, 2013 APUC paid $nil and $29 (2012 - $nil and $nil) in relation to these services.

TREASURY RISK MANAGEMENT

APUC attempts to proactively manage the risk exposures of its subsidiaries in a prudent manner. APUC ensures that both APCo and Liberty Utilities maintain insurance on all of their facilities. This includes property and casualty, boiler and machinery, and liability insurance. It has also initiated a number of programs and policies including currency and interest rate hedging policies 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, interest rate, liquidity and commodity price risk considerations, and credit risk associated with a reliance on key customers. The risks discussed below are not intended as a complete list of all exposures that APUC may encounter. A further assessment of APUC and its subsidiaries' business risks is also set out in the most recent AIF.

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 72% of EBITDA in 2013 and 70% 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 $16.2 million ($0.08 per share) on an annual basis.

APUC manages this risk primarily through the use of natural hedges by using U.S. long term debt to finance its U.S. operations. APUC's policy is not to utilize derivative financial instruments for trading or speculative purposes.

Market price risk

Liberty Utilities is not exposed to market price risk as rates charged to customers are stipulated by the respective regulatory bodies.

On May 15, 2012, APCo 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 APCo's production volume against exposure to the Alberta Power Pool's current spot market rates. For the unhedged portion of production, each $10.00 per MW-hr change in the market prices in the Western region would result in a change in revenue of $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 production volume against exposure to PJM Western Hub current spot market rates. For the unhedged portion of production, each $10 per MW-hr change in the market prices would result in a change in revenue of about $0.3 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 Senate Wind Facility's production volume against exposure to ERCOT North Zone current spot market rates. For the unhedged portion of production, each $10 per MW-hr change in the market prices would result in a change in revenue of about $1.1 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 production volume against exposure to PJM Northern Illinois Hub current spot market rates. For the unhedged portion of production, each $10 per MW-hr change in market prices would result in a change in revenue of about $1.1 million for the year.

For the Sandy Ridge, Senate and Minonk Wind Facilities, in the fourth quarter of 2013 APCo entered into unit contingent financial hedges which commenced January 1, 2014 for a one year period. These hedges are structured to hedge all of the production from the Facilities in excess of the production covered by the hedges described in the three preceding paragraphs. The hedges do not have a minimum volume commitment and hence the facilities do not bear any market risk associated with production. As a result, the Sandy Ridge, Senate and Minonk Wind Facilities now have hedges in place covering 100% of the energy produced.

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, each $10 per MW-hr change in market prices would result in a change in revenue of about $1.1 million for the year.

Credit/Counterparty risk

APUC and its subsidiaries are subject to credit risk through its 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 this risk to be significant as approximately 85% of APCo Renewable Energy division's revenue, approximately 100% of APCo Thermal Energy division's revenue, and over 88.1% of APCo's total revenue is earned from large utility customers having a credit rating of BBB or better.The following chart sets out APCo'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
Renewable Energy Division			
PJM Interconnection LLC	Aa3	33.6	23.1%
Manitoba Hydro	Aa1	27.8	19.1%
Hydro Quebec	Aa2	22.4	15.4%
US Wind Hedge Counterparty[2]	A	12.1	8.3%
Ontario Electricity Financial Corporation	Aa2	11.7	8.0%
Main Public Service[3]	BBB+	9.4	6.4%
Commonwealth Edison	BBB	7.3	5.0%
Total – Renewable		**$ 124.3**	**85.3%**
Thermal Energy Division			
Pacific Gas and Electric Company	A3	16.9	48.9%
Connecticut Light and Power	A-	17.6	51.1%
Total – Thermal		**$ 34.5**	**100.0%**
Total – APCo		**$ 158.8**	**88.1%**

[1] Ratings by Moody's or Standard & Poor's as of February 2014.

[2] Hedge counterparty for the Sandy Ridge, Senate, and Minonk Wind Facilities

[3] Maine Public Service is a subsidiary of Emera.

The remaining revenue is primarily earned by Liberty Utilities. In this regard, the credit risk related to the Liberty Utilities (West) and Liberty Utilities (Central) regions' accounts receivable balances related to the water and wastewater utilities total U.S. $3.3 million which is spread over approximately 93,000 connections, resulting in an average outstanding balance of approximately $35.00 dollars per connection. Liberty Utilities (East) and Liberty Utilities (Central) regions' accounts receivable balances related to the natural gas utilities total U.S. $52.6 million, while the Liberty Utilities (East) and Liberty Utilities (West) regions' accounts receivable balances related to the electric utilities total U.S. 15.7 million. The natural gas and electrical utilities derive over 88% of their revenue from residential customers.

In addition to the counterparty risk related to customer sales outlined above, APCo and Liberty Utilities utilizes 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 APUC Facility is subject to a variable interest rate. The APUC Facility has no amounts outstanding as at December 31, 2013. As a result, a 100 basis point change in the variable rate charged would not impact interest expense.
- The APCo Facility had $124.6 million outstanding as at December 31, 2013. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $1.2 million annually.
- APCo's project debt at its Sanger Thermal Facility has a balance of U.S. $19.2 million as at December 31, 2013. Assuming the current level of borrowings over an annual basis, a 100 basis point change in the variable rate charged would impact interest expense by U.S. $0.2 million annually.
- The Liberty Facility had $80.5 million outstanding as at December 31, 2013. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.8 million annually.
- The Shady Oaks Senior Debt Facility had $129.8 million outstanding as at December 31, 2013. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $1.3 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.

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 APCo and Liberty 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 at each of APCo and Liberty Utilities to meet their liabilities when due.

As at December 31, 2013, APUC and its subsidiaries had a combined $202.6 million of committed and available credit facilities remaining and $13.8 million of cash resulting in $216.4 million of total liquidity and capital reserves.

APUC currently pays a dividend of $0.34 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 dividends paid during the year ended December 31, 2013, cash provided by operating activities exceeded dividends declared by 1.4 times and exceeds Adjusted Cash From Operations by 2.2 times.

The long term portion of debt totals approximately $1,255.6 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
APCo's exposure to commodity prices is primarily limited to exposure to natural gas price risk. Liberty Utilities is exposed to energy price risk in the Liberty Utilities (West) and Liberty Utilities (East) regions. Additionally, Liberty Utilities is exposed to natural gas price risk in the Liberty Utilities (Central) and Liberty Utilities (East) regions.

In this regard, a discussion of this risk is set out as follows:

- APCo's 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.
- APCo's Windsor Locks Thermal Facility's ESA includes provisions which reduce its exposure to natural gas price risk but has exposure to market rate conditions for sales above those to Ahlstrom. 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.
- AES provides short-term energy requirements to various customers at fixed rates. The energy requirements of these customers are estimated at approximately 200,000 MW-hrs in fiscal 2014. While the Tinker facility is expected to provide the majority of the energy required to service these customers, AES anticipates having to purchase approximately 90,000 MW-hrs of its energy requirements at the ISO-NE spot rates to supplement self-generated energy. The risk associated with the expected market purchases of 90,000 MW-hrs is mitigated through the use of short-term financial energy hedge contracts which cover approximately 65,000 MWhrs of AES's anticipated purchases over the next 12 months at an average rate of approximately $59 per MW-hr. For the amount of anticipated purchases not covered by hedge contracts, each $10.00 change per MW-hr in the market prices in ISO-NE would result in a change in expense of $0.3 million on an annualized basis.

Liberty Utilities is exposed to energy price risk in the Liberty Utilities (West) region which is mitigated through a regulatory balancing account. The Liberty Utilities (West) region 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 purchase power agreement 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. In the CalPeco Electric System's 2012 general rate case, a revenue decoupling mechanism and a vegetation management memorandum account were agreed upon. 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.

In the Liberty Utilities (East) region, 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, the 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 and quarterly for large customers. The winning bidder is obligated to provide a full requirements service based on the actual needs of the Granite State Electric System's Default Service customers. Since this is a full requirements service, the winning bidder(s) take on the risk associated with fluctuating customer usage and commodity prices. The supplier is paid for the commodity by the Granite State Electric System which in turns receives pass-through rate recovery through a formal filing and approval process with the NHPUC on a semi-annual basis. The Granite State Electric System is only committed to the winning Default Service supplier(s) after approval by the NHPUC so that there is no risk of commodity commitment without pass-through rate recovery.

In the Liberty Utilities (East) region, the EnergyNorth Gas System purchases pipeline capacity, storage and commodity from a variety of counterparties. The EnergyNorth Gas System's portfolio of assets, planning and forecasting methodology is approved by the NHPUC bi-annually through an Integrated Resource Plan filing. In addition, the EnergyNorth Gas System files with the NHPUC for recovery of its transportation and commodity costs through a semi-annual winter and summer Cost of Gas (COG) filing and approval process. The EnergyNorth Gas System establishes rates for its customers within the COG filing and these rates are designed to fully recover its anticipated transportation and commodity costs. In order to minimize commodity price fluctuations, the EnergyNorth Gas System has implemented a NHPUC approved commodity hedging program designed to hedge approximately 60% 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 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 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 carrying costs to the next year's period COG filing, i.e. winter to winter and summer to summer.

The Liberty Utilities (Central) region 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 Liberty Utilities (Central) region 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 Liberty Utilities (Central) region 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. The Liberty Utilities (Central) region may adjust its rates 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

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 dependence upon APUC businesses, regulatory climate and permits, tax related matters, gross capital requirements, labour relations, reliance on key customers and environmental health and safety considerations. A further assessment of APUC's business risks is set out in the most recent AIF.

Mechanical and Operational Risks

APUC is entirely dependent upon the operations and assets of APUC's businesses. This 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.

The hydro assets of APCo utilize dams to pond water for generation and if the dams burst catastrophic amounts of water would flood downriver from the facility. The units can be subjected to drought conditions and lose the ability to generate during peak load conditions, causing the facilities to miss on 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 wind assets of APCo could catch on fire, and depending on the season could ignite significant amounts of forest or crop downwind from the unit. 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. The wind units risk is mitigated by properly maintaining the units using long term maintenance agreements with the turbine O&M's by 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 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 by the regular maintenance of the boiler system, and by continual monitoring of exhaust gases. Fuel restrictions can be hedged somewhat by long term purchases.

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.

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.

The gas distribution systems owned by Liberty Utilities 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 (APCo and Liberty Utilities) 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 APCo hydroelectric facilities, water rights are generally owned by governments who reserve the right to control water levels which may affect revenue.

Liberty Utilities' 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. The Liberty Utilities (West) region's CalPeco Electric System files a Post-Test Year Adjustment Mechanism ("PTAM") that increases base tariff general rates for inflation. Federal, State and local environmental laws and regulations impose substantial compliance requirements on electricity and natural gas distribution utilities. Operating costs could be significantly affected in order to comply with new or stricter regulatory requirements.

Electricity and natural gas distribution utilities could be subject to condemnation or other methods of taking by government entities under certain conditions. While any taking by government entities would require compensation be paid to Liberty Utilities, and while Liberty Utilities 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.

Liberty Utilities regularly works with its governing authorities to manage the affairs of the business.

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 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.

Liberty Utilities' 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, Liberty Utilities has regular maintenance programs at each facility to ensure its equipment is properly maintained and replaced on a cyclical basis. These maintenance expenses, expenses associated with replacing aging distribution facilities and expenses associated with providing new sources of commodity supply can generally be included in the facility's rate base and thus Liberty Utilities expects to be allowed to earn a return on such investment.

In conjunction with the recent acquisitions the Company assumed certain asset retirement obligations. The asset retirement obligations mainly relate to legal requirements to: (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 adequate insurance which include property, boiler and machinery, environmental and excess liability policies.

APCo'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; State/Provincial Agencies such us, 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.

Liberty Utilities 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, Liberty Utilities 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, Liberty Utilities investigates 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. 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. Liberty 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 Liberty Utilities (East) region'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 Liberty Utilities, 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 Liberty Utilities 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 Liberty Utilities believes that obligations imposed on it because of those sites will not have a material impact on its results of operations or financial position.

Liberty Utilities estimates the remaining cost of these MGP-related environmental cleanup activities will be $77.7 million which at a discount rates ranging from 3.8% to 4.5% represents $69.6 million at December 31, 2013, which has been accrued as Liberty Utilities' estimate of costs for known issues. By rate orders, the Regulator provided for the recovery of site investigation and remediation costs and accordingly, at December 31, 2013 the Company has reflected a regulatory asset of $80.4 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 Season

The hydroelectric operations of APCo are impacted by seasonal fluctuations. 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. It is, however, anticipated that due to the geographic diversity of the facilities, variability of total revenues will be minimized.

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 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 Liberty Utilities (West) and Liberty Utilities (Central) regions' 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.

Prior to January 1, 2013, the Liberty Utilities (West) region was exposed to volume sales risk related to seasonal weather variations at the CalPeco Electric System. Effective on January 1, 2013, pursuant to a CPUC approved Rate Case decision, a Base Revenue Requirement Balancing Account (BRRAM) rate mechanism has been implemented. The BRRAM 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.

The Liberty Utilities (West) region's demand for energy is primarily affected by weather conditions and conservation initiatives. Above normal snowfall in the Lake Tahoe area brings more tourists with an increased demand for electricity by small commercial customers. The Liberty Utilities (West) 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 BRRAM mitigates this risk.

The Liberty Utilities (East) and Liberty Utilities (Central) regions' natural gas demand is driven by the seasonal heating requirements of its residential, commercial, and industrial customer. That is, the colder the weather the greater the demand for natural gas to heat homes and businesses. As such, the Liberty Utilities (East) and Liberty Utilities (Central) regions' natural gas demand profiles typically peaks in the winter months of January and February and declines in the summer months of July and August. At the Peach State Gas System, 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.

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. The Second Circuit Court of Appeals, among other things, on November 2, 2010 dismissed the claims against APUC in the civil proceedings. The bankruptcy proceedings are continuing, with a Second Circuit Court of Appeal hearing scheduled for December 12, 2012 to hear the appeal of the District Court's October 25, 2011 decision holding that APUC does not have a security interest in the monies transferred by Trafalgar before it filed for bankruptcy protection.

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.

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. Cross examinations were held in November, 2013. A hearing is scheduled for early 2014.

Dimos and Katsekas breach of contract claim

On September 30, 2013, previous owners of the Clement Dam hydro facility, filed a demand for arbitration with Algonquin Power Fund (America) Inc. 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 March, 2015.

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. Discovery is being scheduled.

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 project in Ontario, Canada. Plaintiffs attempted to serve Algonquin with the complaint on February 11, 2014.

Bryson School District in Texas property taxes claim

On February 10, 2014, APCo received correspondence from the Bryson 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. The assertion is being disputed.

Obligations to serve

Liberty Utilities 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, Liberty Utilities may be required to solicit additional capital or obtain additional borrowings to finance these future construction obligations.

Quarterly Financial Information

The following is a summary of unaudited quarterly financial information for the eight quarter ended December 31, 2013:

Millions of dollars (except per share amounts)	1st Quarter 2013	2nd Quarter 2013	3rd Quarter 2013	4th Quarter 2013
Revenue	$ 193.1	$ 148.8	$ 127.9	$ 205.3
Adjusted EBITDA	61.8	56.5	40.5	67.6
Net earnings / (loss) attributable to shareholders from continuing operations	20.4	15.8	6.3	19.8
Net earnings / (loss) attributable to shareholders	19.2	(18.1)	6.0	13.1
Net earnings / (loss) per share from continuing operations	0.10	0.08	0.02	0.09
Net earnings / (loss) per share	0.10	(0.09)	0.02	0.06
Adjusted net earnings	19.4	15.4	6.9	18.5
Adjust net earnings per share	0.10	0.08	0.03	0.08
Total Assets	2,990.7	3,201.8	3,156.4	3,472.6
Long term debt*	917.5	1,091.5	1,092.0	1,255.6
Dividend declared per common share	0.08	0.09	0.09	0.09
	1st Quarter 2012	2nd Quarter 2012	3rd Quarter 2012	4th Quarter 2012
Revenue	$ 58.1	$ 58.7	$ 93.0	$ 138.9
Adjusted EBITDA	21.4	22.2	20.8	24.0
Net earnings / (loss) attributable to shareholders from continuing operations	2.0	5.3	(0.6)	6.8
Net earnings/(loss) attributable to shareholders	2.3	6.1	(0.2)	6.4
Net earnings / (loss) per share from continuing operations	0.01	0.03	—	0.04
Net earnings/(loss) per share	0.02	0.04	—	0.03
Adjusted net earnings	5.0	6.5	1.1	6.5
Adjust net earnings per share	0.04	0.04	0.01	0.03
Total Assets	1,265.6	1,416.0	1,967.1	2,779.0
Long term debt[1]	391.9	461.8	705.1	770.8
Dividend declared per common share	0.07	0.07	0.08	0.08

[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 $58.1 million and $205.3 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 $19.2 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.

Disclosure Controls

At the end of the fiscal year ended December 31, 2013, 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, 2013, 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, 2013, APUC acquired the Shady Oaks Wind Facility, the Pine Bluff Water System, the Peach State Gas System and the New England Gas System. The financial information for these business acquisitions is included in this MD&A and in Note 3 to the consolidated financial statements. As permitted by National Instrument 52-109 and the U.S. Securities and Exchange Commission, the Company excluded these acquisitions from its evaluation of the effectiveness of APUC's internal controls over financial reporting as of December 31, 2013 due to the complexity associated with assessing internal controls during integration efforts and the proximity of some of the acquisitions to year-end.

Management conducted an evaluation of the design and operation of APUC's internal control over financial reporting as of December 31, 2013 based on the criteria set forth in Internal Control – Integrated Framework (1992) 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, 2013.

During the year ended December 31, 2013, there has been no change in APUC's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, APUC's internal control over financial reporting. APUC continues to implement its internal control structure over the operations of the acquired businesses discussed above.

Critical Accounting Estimates and Polices

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 and Intangibles

The provisions for depreciation of utility 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, 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 Liberty Utilities' 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 write 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. Derivative instruments that do not meet the normal purchases and sales exception are recorded at fair value. Changes in the derivative's fair value are recognized as regulatory assets or liabilities when the regulator permits recovery of the hedging strategy. For derivative designated in a cash flow hedge relationship, the effective portion of the change in fair value is deferred to accumulated other comprehensive income, until the hedged transaction occurs and is recognized in earnings. The ineffective portion is immediately recognized in earnings. For derivative or financial instruments designated as a hedge of the foreign currency exposure of a net investment in foreign operations, foreign currency transaction gain or loss that are effective as an economic hedge of the net investment in a foreign operation are reported in other comprehensive income.

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

Fair value of assets and liabilities acquired in a business combination

The Company has closed 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 SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com.

Exhibit 99.4



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Consent of Independent Registered Public Accounting Firm

We consent to the inclusion in this annual report on Form 40-F of Algonquin Power & Utilities Corp. (the "Company") of our Report of Independent Registered Public Accounting Firm dated March 14, 2013, except for the asset held for sale and discontinued operations adjustments to the 2012 comparative amounts discussed in note 20 to the consolidated financial statements of the Company for the fiscal year ended December 31, 2013, which is dated as of March 14, 2014, on the consolidated balance sheet as of December 31, 2012, and the related consolidated statements of operations, comprehensive income (loss), equity and cash flows for the year then ended, which is contained in this annual report on Form 40-F of the Company for the fiscal year ended December 31, 2013.

We also consent to the incorporation by reference of the above-mentioned Report of Independent Registered Public Accounting Firm in the Registration Statement on Form S-8 (No.333-177418) of the Company

/s/ KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
March 28, 2014

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 14, 2014, with respect to the consolidated balance sheet of Algonquin Power & Utilities Corp. as at December 31, 2013, and the consolidated statements of operations, comprehensive income (loss), changes in equity, and cash flows for the year then ended December 31, 2013, and the effectiveness of internal control over financial reporting of Algonquin Power & Utilities Corp as at December 31, 2013.

We also consent to the incorporation by reference of our reports dated March 14, 2014 in the Registration Statement (Form S-8 No. 333-177418) pertaining to Algonquin Power & Utilities Corp.

/s/ Ernst & Young, LLP

Chartered Accountants
Licensed Public Accountants

Toronto, Canada
March 28, 2014

A member firm of Ernst & Young Global Limited

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 28, 2014

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 28, 2014

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 28, 2014

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 28, 2014

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