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Section 1: 40-F (40-F)

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

For the fiscal year ended December 31, 2012 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

N/A

Name of each exchange on which registered

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:

Annual Information Form

Audited Annual Financial Statements

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

As of December 31, 2012, there were 188,763,486 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

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

No

ANNUAL INFORMATION FORM

The Annual Information Form of Algonquin Power & Utilities Corp. (“Algonquin”) for the fiscal year ended December 31, 2012 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, 2012 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, 2012 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 53) in the Management’s Discussion and Analysis for the fiscal year ended December 31, 2012, 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, 2012, based on the framework established in *Internal Control– Integrated Framework* 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, 2012.

During the year ended December 31, 2012, Algonquin acquired Granite State Electric Company, EnergyNorth Natural Gas Inc., Liberty Energy (Midstates) Corp., Wind Portfolio SponsorCo LLC and Wind Portfolio Holdings LLC associated with total assets of \$757.7 million and total revenues of \$117.0 million included in the consolidated financial statements of the Company as of and for the year ended December 31, 2012. 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, 2012 due to the complexity associated with assessing internal controls during integration efforts and the proximity of certain of the acquisitions to year-end.

KPMG LLP, the independent registered public accounting firm of Algonquin, which audited the consolidated financial statements of Algonquin for the year ended December 31, 2012, has also issued an attestation report on the effectiveness of Algonquin’s internal control over financial reporting as of December 31, 2012.

b. Auditor’s attestation report on internal control over financial reporting

The attestation report of KPMG LLP, the independent registered public accounting firm of Algonquin, on the Company’s internal control over financial reporting as of December 31, 2012, 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 53) in the Management’s Discussion and Analysis for the fiscal year ended December 31, 2012, 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, 2012, 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, 2012 were pre-approved by the audit committee.

OFF-BALANCE SHEET ARRANGEMENTS

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

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

The information provided under the heading “Contractual Obligations” (page 39) in the Management’s Discussion and Analysis for the fiscal year ended December 31, 2012, 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, 2012, 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” and “per share cash provided by operating activities” throughout the Management’s Discussion and Analysis for the fiscal year ended December 31, 2012 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” and Adjusted EBITDA 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” and “per share cash provided by operating activities”. 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” and “per share cash provided by operating activities” 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, 2012, 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, 2012, 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, 2012 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.

EXHIBIT INDEX

<u>Exhibit</u>	<u>Description</u>
99.1	Annual Information Form for the year ended December 31, 2012
99.2	Audited Annual Financial Statements for the year ended December 31, 2012
99.3	Management's Discussion & Analysis for the year ended December 31, 2012
99.4	Consent Letter from KPMG LLP, Chartered Accountants
99.5	Certifications of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
99.6	Certifications of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
99.7	Certifications of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.8	Certifications of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101	Interactive Data File

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All information contained in this Annual Information Form (“AIF”) is presented as at March 28, 2013, 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.

1. CORPORATE STRUCTURE

1.1 Name, Address and Incorporation

Algonquin Power & Utilities Corp. (“**APUC**” or the “**Corporation**”) was originally incorporated under the *Canada Business Corporations Act* (“**CBCA**”) 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 (the “**Common Shares**”), transferred its existing operations to a newly formed independent corporation 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. (“**APCo**”) (See *General Development of the Business – The Unit Exchange*).

APUC’s principal holdings are its trust units (“**Trust Units**”) of APCo and shares of Liberty Utilities Co. (“**Liberty Utilities**”). Liberty Utilities’ businesses operate under three separately managed regions – Liberty Utilities (West), Liberty Utilities (Central), and Liberty Utilities (East).

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

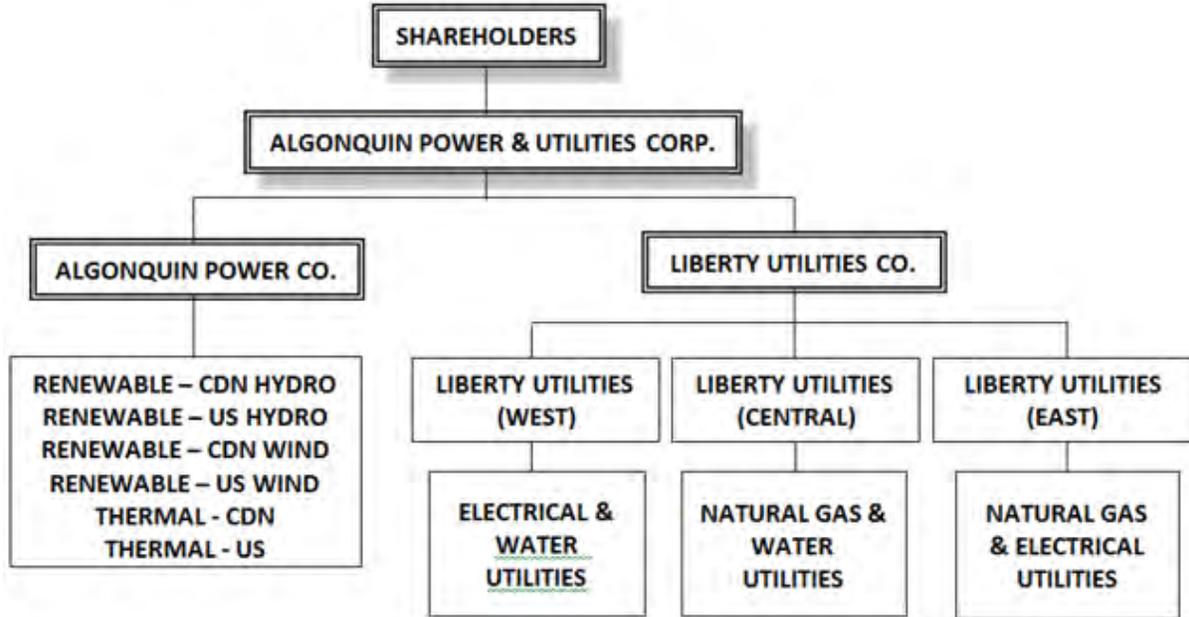
(a) Subsidiaries

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., 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 and operates the entities within the Liberty Utilities (West), Liberty Utilities (Central), and Liberty Utilities (East) regions. Each of APCo, Liberty Utilities (West), Liberty Utilities (Central), and Liberty Utilities (East) regions have their own subsidiaries and ownership chains.

The subsidiaries of APCo include the ownership chains of Algonquin Power Trust (“**APT**”), and Algonquin Power Fund (Canada) Inc. (“**APFC**”). APT’s subsidiaries include the ownership chain of Algonquin Power Operating Trust (“**APOT**”), and APFC’s subsidiaries include the ownership chain of Algonquin Power Fund (America) Inc. (“**APFA**”). The Liberty Utilities operating regions include Liberty Utilities (West), a region currently holding an electrical distribution utility located

in California, and water distribution and wastewater treatment utilities located in Arizona. The Liberty Utilities (Central) region currently holds water distribution and wastewater treatment utilities located in Arkansas, Illinois, Missouri, and Texas, and natural gas utilities located in Illinois, Iowa, and Missouri. The Liberty Utilities (East) region holds an electrical distribution utility and a natural gas distribution utility located in New Hampshire.

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 68.9% of APFC, and 62.5% of the issued and outstanding shares of Cornwall Solar Inc.

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 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 (“**Peel**”) 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 Algonquin Power Energy From Waste Inc. (“**APEFW**”), an Ontario corporation that owns the EFW Facility.

APT also holds interests in certain of APCo’s Canadian hydroelectric Facilities. It directly owns the hydroelectric Hydraska Facility and the Arthurville Facility, and owns both the general partnership and the limited partnership interests in Algonquin Power (Campbellford) Limited Partnership (“**Campbellford LP**”), an Ontario limited partnership which operates a 4 megawatt (“**MW**”) hydroelectric generation station on the Trent River near Campbellford, Ontario (the “**Campbellford Facility**”). APT also directly owns a 42% limited partnership interest in the Algonquin Power (Mont-Laurier) Limited Partnership (the “**Mont-Laurier Partnership**”), a Québec limited partnership, which owns the Mont-Laurier facility and the Côte Ste.-Catherine facility. APEFW owns the remaining 58% partnership interests, comprised of a 46.5% limited partnership interest and an 11.5% general partnership interest.

APT owns Corporation D’Investissements Éoliennes Algonquin Power (“**Éoliennes**”), a Canadian corporation. Éoliennes indirectly owns St. Ulrich Wind Energy Investments L.P. (“**St. Ulrich LP**”), a Québec limited partnership, through its ownership of the limited partnership of St. Ulrich LP and Société en Commandite Algonquin (Éoliennes), a Québec limited partnership, and its direct ownership of the general partner of St. Ulrich LP, named Corporation D’Investissements Éoliens St-Laurent Inc. (“**Corporation St-Laurent**”), a Québec corporation. Corporation St-Laurent is the 50% owner of Saint-Damase Wind Energy Fleur de Lis General Partner Corporation, a federal corporation, which is the general partner of the partnership known as Saint-Damase Wind Energy Fleur de Lis Limited Partnership (“**St. Damase LP**”). St. Damase LP has an interest in the Saint – Damase wind energy project and described below in “*Description of the business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Development – Current Development Projects*”. St. Ulrich LP owns a 49.995% equity interest in the St. Damase LP, the general partner owns a .01% equity interest, and a non-Algonquin party owns the remaining 49.995% equity interest. APT also has an interest in Éoliennes Belle- Rivière, société en commandite (“**Belle Rivière**”), a Quebec partnership and the owner of the Val- Éo wind energy project, also described below in “*Description of the business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Development – Current Development Projects*”. It owns a 25% equity interest in the general partner, 9231-5498 Québec Inc. and it also holds a 24.995% limited partner 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 Facility**”). The BCI Facility is owned by Brampton Cogeneration Limited Partnership, an Ontario partnership, the partners of which are Brampton Cogeneration Inc. (“**BCI**”), 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 (vote on only specific matters) in the limited partnership. 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 Facility**”). The APOT entity that owns the St. Leon 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 30.11% 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 Class 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% 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. 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 GP also owns 100% of the ownership interests in St. Leon II Wind Energy LP (“**St. Leon II**”), a Manitoba partnership, the general partner of which is St. Leon II Wind Energy GP Inc., a Manitoba corporation, which is also owned by St. Leon LP. St. Leon II owns the 16.5 MW wind facility (the “**St. Leon II Facility**”), an expansion of the St. Leon Facility, located at St. Leon, Manitoba.

APOT is the sole limited partner in Red Lily Wind Power II Limited Partnership, a Saskatchewan limited partnership, the general partner of which is Red Lily Wind Power II GP Inc., a Saskatchewan corporation, which is also owned by APOT. APOT also owns Loyalist Wind Project GP Inc., an Ontario corporation, which is the general partner, holding 0.01% interest in Loyalist Wind Project LP (“**Loyalist LP**”), an Ontario limited partnership. APUC is the majority limited partner of Loyalist LP, holding the remaining 99.99% interest.

APOT has two ownership interests in Alberta. First, it is the beneficial owner of one hydroelectric facility in Alberta (the “**Dickson Dam Facility**”). APOT owns 50% of Valley Power Corp., an Ontario corporation, which holds a 0.0001% limited partnership interest partner in Valley Power LP, an Alberta limited partnership which owns the Alberta biomass facility (the “**Valley Power Facility**”). APOT also directly holds a 49.9995% limited partnership interest in Valley Power LP.

APFC Group

APFC, a subsidiary of APUC, is an Ontario corporation and it controls the entities that own the majority of APUC’s hydroelectric facilities in Canada. APFC owns Algonquin Power (America) Inc., (“**APA**”) 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 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 Rapids facility. In Québec, APFC directly owns the facilities known as Rawdon, Hydro Snemo, St. Raphael, Belleterre and St. Brigitte Facilities. APFC also holds a direct interest in Société Hydro-Donnacona, S.E.N.C. (the “**S.E.N.C.**”), the owner of the Donnacona Facility. The 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. In Newfoundland, APFC holds a 45% partnership interest in the Algonquin Power (Rattlebrook)

Partnership, a Newfoundland partnership that owns the Rattlebrook Facility. APFC also owns 100% of Algonquin Power Services Canada Inc., a Canadian corporation that provides purchasing services to Canadian APCo entities.

APFC also owns 1631667 Alberta ULC, an Alberta unlimited liability corporation.

APFA Group

APFA, a Delaware corporation, is owned by APA. APFA owns or holds interest in the hydroelectric, thermal cogeneration, and wind energy entities and facilities in the U.S.

APFA owns Algonquin Power Sanger LLC (“**Sanger LLC**”), a California limited liability company, and Algonquin Power Windsor Locks LLC (“**Windsor LLC**”), a Connecticut limited liability company. These entities own the U.S. cogeneration Sanger and Windsor Locks 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 indirectly owns numerous hydroelectric facilities through majority interests ranging from 99.7% to 99.99% in the subsidiaries described in this paragraph, with Algonquin Power Fund (America) Holdco Inc. (“**Algonquin Holdco**”), a Delaware corporation owned by APFA, holding the remaining interests. The Vermont partnership Moretown Hydro Energy Company owns the Moretown Facility. The New Hampshire limited partnerships Gregg Falls Hydroelectric Associates Limited Partnership, Pembroke Hydro Associates Limited Partnership and Mine Falls Limited Partnership own the Gregg Falls, Pembroke and Mine Falls Facilities, respectively.

APFA owns the New Hampshire limited liability company Clement Dam Hydroelectric, LLC which owns the Clement Dam Facility. The Franklin, Beaver Falls and Lakeport Facilities are owned by, respectively, Franklin Power, LLC, a New Hampshire company, Algonquin Power (Beaver Falls) LLC, a Delaware corporation and Lakeport Hydroelectric Corp., a New Hampshire corporation. Court Street Investments Inc. (“**Court Street**”), a Massachusetts corporation, is owned 100% by APFA and owns CSI Oswego Corp., a Delaware corporation, which is a partner in Oswego Hydro Partners L.P., the Delaware partnership that owns the Phoenix Facility. The other partner in this partnership is Oswego Energy Corp., a Delaware corporation, which is 100% owned by Oswego Power Company, Inc., a Massachusetts corporation, which in turn is 100% owned by APFA. The remaining hydroelectric facilities in the United States are the Great Falls and Lochmere Facilities. The Great Falls Facility is owned by the Great Falls Hydroelectric Company Limited Partnership, a Maryland limited partnership in which APFA holds a 98% limited partner interest. Great Falls Energy, LLC holds the remaining 2% general partner interest. Great Falls Energy, LLC is a Maryland limited liability company wholly owned by APFA. The Lochmere Facility is owned by the Indiana general partnership HDI Associates I, which is held 0.1% by Algonquin Holdco and 99.9% by APFA.

On March 14, 2013, affiliates of APCo entered into an agreement to sell the following facilities: Phoenix Facility, Beaver Falls Facility, Greggs Falls Facility, Pembroke Facility, Clement Facility, Franklin Facility, Lochmere Facility, Lakeport Facility, Mine Falls Facility, and Great Falls Facility. The sale is subject to certain regulatory approvals and other conditions precedent. The transaction is expected to close in 2013.

APFA owns Algonquin Tinker Gen Co. (“**Tinker Gen Co.**”) and Algonquin Northern Maine Gen Co. (“**Northern Maine Gen Co.**”), both Wisconsin companies. Tinker Gen Co. is also registered

in New Brunswick, and Northern Maine Gen Co. is also registered in Maine. Tinker Gen Co. operates the 36.8MW of electrical generating assets in New Brunswick (the “**Tinker Assets**”), 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 (“**AES**”) that is also registered in Connecticut, District of Columbia, Maine, Maryland, New Brunswick and Ohio. AES 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 Energy USA, LLC (“**Gamesa USA**”), 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-Algonquin partners, JPM Capital Corporation, Morgan Stanley Wind LLC, and Gear Wind LLC, collectively hold 100% of the non-managing Class A interest in WP HoldCo, which in turn owns Wind Energy Portfolio Holdings I, LLC (“**WE HoldCo**”). WE HoldCo directly owns the three entities which each own separate wind projects in the USA. 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.

Through a chain of subsidiaries, 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. These subsidiaries were acquired effective January 1, 2013.

APFC also 100% owns Algonquin Power Services America LLC, a Delaware corporation that provides purchasing services to APCo entities operating in the U.S.

(ii) **Utilities Business**

Liberty Utilities (West) & Liberty Utilities (Central) Region Water and Wastewater Utilities

Liberty Water Co. (“**Liberty Water**”), a Delaware company, is the parent company of the water and wastewater entities within the Liberty Utilities (West) and Liberty Utilities (Central) regions. On December 22, 2010, APCo completed a corporate reorganization involving Liberty Water wherein 100% of the issued and outstanding common shares of Liberty Water were transferred from APCo to Liberty Utilities.

Liberty Water indirectly owns the water and wastewater businesses located in Arizona, Texas, Missouri, Illinois and Arkansas, in each case through a 100% wholly-owned subsidiary, with the exception of Northwest Sewer Inc., which it owns directly and the Entrada Del Oro Sewer Company, Inc. (“**Entrada**”) which it currently operates and in which it holds a beneficial interest in the shares of the company pending regulatory approval of its acquisition by Liberty Water. All of these 100% wholly-owned subsidiaries (except Northwest Sewer, Inc.) 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: Bella Vista Water Co., Inc. owns the Bella Vista Facility; Black Mountain Sewer Corporation owns the Black Mountain Facility; Gold Canyon Sewer Company owns the Gold Canyon facility; Litchfield Park Service Company owns the Litchfield facility; Northern Sunrise Water Company, Inc. owns the Northern

Sunrise facility; Rio Rico Utilities, Inc. owns the Rio Rico facility; and Southern Sunrise Water Company, Inc. owns the Southern Sunrise facility. Northwest Sewer, Inc., an Arizona corporation, has undertaken 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, operate a wastewater treatment utility in those areas. Entrada, discussed above, is an Arizona corporation, and it owns the beneficial interest in the Entrada Del Oro facility. In Texas, the following Texas corporations own the following facilities: Tall Timbers Utility Company, Inc. owns the Tall Timbers facility; Woodmark Utilities, Inc. owns the Woodmark facility; Algonquin Water Resources of Texas, 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 Algonquin Seaside Resort, LLC., a Texas limited liability company, owns water and wastewater treatment assets at the Seaside Resort. In Missouri, Algonquin Water Resources of Missouri, 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, Algonquin Water Resources of Illinois, LLC, an Illinois limited liability company, owns assets for the Fox River Resort.

Liberty Energy Utilities Co. ("**Liberty Energy**"), a Delaware corporation, is owned by Liberty Utilities. Liberty Energy owns Liberty Utilities (Pine Bluff Water) Inc., which owns and operates the Pine Bluff Water Facility located in Pine Bluff, Arkansas. This facility was acquired by Liberty Utilities on February 1, 2013.

Liberty Utilities (West) Region Electrical Distribution Utility

Liberty Energy owns California Pacific Utilities Ventures, LLC, a California limited liability company ("**CPUV**"), which in turn owns California Pacific Electric Company, LLC, a California limited liability company ("**Calpeco**"). Calpeco owns an electricity distribution utility in the Lake Tahoe basin and surrounding areas in California ("**California Utility**").

Liberty Utilities (Central) Region Natural Gas Distribution Utility

Liberty Energy also owns Liberty Energy (Midstates) Corp. ("**Liberty Midstates**"), a Missouri corporation. Liberty Midstates owns natural gas distribution utility assets in Missouri, Iowa and Illinois (the "**Midwest Gas Utilities**"). These assets were purchased from Atmos Energy Corporation ("**Atmos**") on August 1, 2012.

Liberty Utilities (East) Region Electrical Distribution and Natural Gas Distribution Utility

Liberty Energy also owns Liberty Energy Utilities (New Hampshire) Corp. ("**Liberty Energy (NH)**"), a Delaware corporation registered in New Hampshire. Liberty Energy Utilities (NH) owns Granite State Electric Company ("**Granite State Electric Utility**") and EnergyNorth Natural Gas Inc. ("**EnergyNorth Gas Utility**"). Both Granite State Electric Utility and EnergyNorth Gas Utility were acquired from National Grid USA ("**National Grid**") on July 3, 2012.

Liberty Energy also owns Liberty Energy (Georgia) Corp. ("**Liberty Georgia**"), a Georgia corporation. Liberty Georgia will own natural gas distribution utility assets in Georgia (the "**Georgia Utility**"). Liberty Georgia has entered into an agreement to acquire these assets from Atmos. The acquisition is expected to close on or about April 1, 2013.

(iii) **Other**

Outside of APCo, Liberty Utilities (West), Liberty Utilities (Central) and Liberty Utilities (East) and their respective subsidiary entities as described above, APUC beneficially owns, directly or indirectly 100% of the following: 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 owns the following 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.

(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 rate 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 Rapids 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 facility.

2. GENERAL DEVELOPMENT OF THE BUSINESS

2.1 General

(a) **The Unit Exchange**

APUC is incorporated under the *Canada Business Corporations Act*. This is the parent company to Algonquin Power Co. (“**APCo**”) through a transaction (the “**Unit Exchange**”) in which APCo’s unitholders exchanged their Trust Units of APCo, on a one-for-one basis, for Common Shares of the Corporation. As a result of the Unit Exchange, APCo itself became a wholly-owned subsidiary of the Corporation and all of the unitholders of APCo became shareholders of the Corporation. The Unit Exchange did not result in any change to the underlying business operations of APCo and accordingly, for accounting purposes, the Corporation is considered a continuation of APCo.

(b) **Business Strategy**

APUC's business strategy is to maximize long term shareholder value as a dividend paying, growth-oriented corporation in the independent power and rate regulated utilities business sectors. APUC is committed to delivering a total shareholder return comprised of dividends augmented by capital appreciation arising through dividend growth supported by increasing cash flows and earnings. Through an emphasis on sustainable, long-view renewable power and utility investments, over a medium-term planning horizon, APUC strives to deliver annualized per share earnings growth of more than 5% and continued growth in its dividend supported by these increasing cash flows, earnings and additional investment prospects.

APUC's current quarterly dividend to shareholders is \$0.0775 per share or \$0.31 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, reduce short term debt obligations and mitigate the impact of fluctuations in foreign exchange rates. Additional increases in the level of dividends paid by APUC are at the discretion of the APUC Board of Directors (the "**Board**") and dividend levels shall be reviewed periodically by the Board in the context of available cash 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 produces stable earnings through a diversified portfolio of renewable power and utility businesses owned and operated by its subsidiary entities. APUC conducts its business primarily through two autonomous 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 utility systems. These businesses of APUC are herein referred to as the "**APUC Businesses**".

APCo – Independent Power Generation

APCo generates and sells electrical energy through a diverse portfolio of renewable power generation and clean thermal power generation facilities across North America. APCo seeks to deliver continuing growth through development of greenfield power generation projects, accretive acquisitions of electrical energy generation facilities as well as development of expansion opportunities within APCo's existing portfolio of independent power facilities. APCo's renewable energy division develops and operates APCo's hydroelectric, solar and wind power facilities. APCo's thermal energy division develops and operates co-generation, energy-from-waste, and steam production facilities.

The renewable power and thermal energy generation business of APCo is managed with an emphasis on growth through the development of green-field projects and opportunities within APCo's existing portfolio. This is achieved through APCo's development division which seeks to build on APCo's expertise in the origination of greenfield renewable energy projects, expanding APCo's existing portfolio of renewable and thermal energy assets for further growth, and capitalizing on new opportunities as they arise.

APCo's renewable energy division generates and sells electrical energy through a diverse portfolio of clean, renewable power generation and thermal power generation facilities across North America. APCo owns or has interests in hydroelectric facilities with a combined generating capacity of approximately 170 MW.

APCo also owns or has interests in wind powered generating stations with a combined generating capacity of 650 MW.

Approximately 84% of the electrical output from the hydroelectric and wind generating facilities is sold pursuant to long term power purchase agreements ("PPAs") which have a weighted average remaining contract life of 15 years

APCo owns or has interests in thermal energy facilities with approximately 341 MW of installed generating capacity. Approximately 95% of the electrical output from the owned thermal facilities is sold pursuant to long term PPA and which have a weighted average remaining contract life of 7 years. Detailed information on the facilities owned and operated by APCo is set out in Schedules A and B.

Liberty Utilities - Utilities

Liberty Utilities is a diversified rate regulated utility providing electricity, natural gas, water distribution and wastewater collection utility services. 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 of the California Utility serve approximately 46,955 active electric connections in the State of California. Liberty Utilities (West) region's regulated water and wastewater utility systems serve approximately 66,550 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 82,050 active natural gas connections located in the States of Missouri, Illinois, and Iowa and the regulated water distribution and wastewater collection utilities serve approximately 11,500 water and wastewater customers located in the States of, Illinois, Missouri, Texas and, as of February 1, 2013, the State of Arkansas.

Liberty Utilities (East) region is comprised of regulated natural gas and electric distribution utility systems located in the State of New Hampshire providing regulated local electrical utility services to approximately 43,250 active electric connections and regulated local gas distribution utility services to approximately 87,650 active natural gas connections. Upon completion of certain pending acquisitions of natural gas utility systems located in Georgia and Massachusetts, an additional 114,000 customers will be added to the Liberty Utilities (East) region.

These utilities generally operate under rate regulation, overseen by public utility commissions of the State in which they operate. 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 2010

Corporate

At the annual general meeting on June 23, 2010 (the “**Meeting**”), APUC adopted a Shareholders’ Rights Plan (the “**Rights Plan**”). See “*Description of Capital Structure – Shareholders’ Rights Plan*”.

APCo – Power Generation

(i) Tinker Facility

On January 12, 2010, APCo completed the acquisition of three hydroelectric generating stations, a 34.5MW hydroelectric generating facility with sufficient reservoir storage capability to move significant amounts of energy from off-peak to on-peak generation located on the Aroostook River near the Town of Perth-Andover, New Brunswick (the “**Tinker Facility**”), a 0.9MW run-of-river hydroelectric generating facility located in Northern Maine (the “**Caribou Facility**”) and a 1.4MW run-of-river hydroelectric generating facility located in Northern Maine (the “**Squa Pan Facility**”).

APCo also acquired certain thermal generating facilities in Northern Maine and New Brunswick utilized for installed reserve capacity, not continuous generation, and New Brunswick Public Utilities Board regulated transmission lines and interconnections which allow direct and indirect access to multiple electricity markets (Northern Maine ISA, New Brunswick ISO and ISO-NE).

(ii) Algonquin Energy Services Inc.

In connection with the acquisition of the Tinker Facility, on February 4, 2010, APCo acquired an energy marketing company which markets the energy generated from the Tinker Facility. AES is managing this business and it is anticipated that the majority of the energy sold by AES will be supplied through generation from the Tinker Assets, based on historical long term average levels of hydroelectric energy generation of these facilities. AES primarily involves standard offer contracts for the supply of energy to commercial and industrial customers in northern Maine, as well as energy purchase obligations with the ISO-NE required to supplement self-generated energy.

AES’ business consists of a series of short-term energy supply agreements. These include energy sales to a town in New Brunswick, standard offer service contracts with three local electric utilities in northern Maine, and a series of direct energy contracts with commercial buyers also in northern Maine.

(iii) **EFW Facility**

A capital upgrade at the EFW Facility was completed in July 2010 and has resulted in higher throughput and lower operating costs per tonne at the Facility in 2011 as compared to periods prior to the upgrade.

Liberty Utilities

(i) **California Utility**

On January 1, 2011, APUC, in partnership with Emera, completed the transaction and acquired the assets comprising an electrical generation and regulated utility (the “**California Utility**”) for a gross purchase price of U.S. \$136.1 million, subject to certain working capital and other closing adjustments from Sierra Pacific Power Company d/b/a NV Energy and Calpeco dated April 22, 2009. Liberty Utilities acquired 50.001% and Emera acquired 49.999% of California Pacific Utility Ventures LLC, which owns 100% of the purchaser of the California Utility assets, Calpeco. On December 21, 2012, APUC acquired the remaining 49.999% ownership in California Pacific Utility Ventures LLC from Emera and as a result, APUC now owns 100% of the California Utility (see Fiscal 2012 highlights).

(ii) **New Hampshire Utility**

On December 9, 2010, APUC announced that Liberty Energy had entered into agreements to acquire all issued and outstanding shares of Granite State Electric Utility, a regulated electric distribution utility, and EnergyNorth Gas Utility, a regulated natural gas distribution utility from National Grid, as outlined in the share purchase agreements by and between National Grid and Liberty Energy entered into on December 8, 2010 and amended and restated on January 11, 2011.

For a more detailed discussion of this acquisition, see “*General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2012 – Liberty Utilities – Acquisition of New Hampshire Utility*”.

(iii) **Rate Cases**

Liberty Utilities (West) had ongoing rate cases at a number of its utilities which were processed throughout 2010. During the year ended December 31, 2010, Liberty Utilities completed rate case proceedings at nine utilities in Arizona and Texas which on an annualized basis were expected to contribute an additional U.S. \$10.2 million in revenue. As these rate cases were settled at various times throughout the year ended December 31, 2010, approximately U.S. \$2.3 million of the overall annualized revenue increase from rate cases completed in Arizona and Texas was achieved in the year. One additional rate case requesting U.S. \$1.1 million in annual revenue requirement was concluded in the first quarter of 2011.

(iv) **Senior Debt Financing**

The acquisition of the California Utility was funded in part with the proceeds of a U.S. \$70 million senior unsecured private debt placement at the utility entered into on December 29, 2010. The

private placement is a senior unsecured private placement with U.S. institutional investors, and is an obligation solely of the California Utility. The notes are fixed rate 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.

On December 22, 2010, Liberty Water completed a private placement financing of senior unsecured 5.6% notes for gross proceeds of approximately U.S. \$50 million. The private placement is a senior unsecured private placement with U.S. institutional investors, and is an obligation solely of Liberty Water. The notes have a 10 year term bearing interest until June 2016, at which point annual principal repayments of U.S. \$5.0 million will commence. The funds were used to reduce outstanding indebtedness under APCo's senior credit facility ("**APCo Credit Facility**").

(b) **Fiscal 2011**

Corporate

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

On October 27, 2011, APUC completed a public offering (the "**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, all of the remaining issued and outstanding principal amount, of Series 1A 7.5% convertible unsecured subordinated debentures due November 30, 2014 (the "**Series 1A Debentures**") and issued 430,666 Common Shares of APUC upon the redemption. Between January 1, 2011 and the Series 1A Redemption Date, \$60.339 million principal amount of Series 1A Debentures were converted by debenture holders into 14,788,976 shares of APUC.

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

On April 29, 2011, APUC entered into a strategic investment agreement (the "**Strategic Investment Agreement**") with 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 general meeting held on June 21, 2011.

APUC share purchases are made 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. The acquisition and conversion of subscription receipts is subject to approvals required under applicable laws, including the rules of the TSX.

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 Repowering

The Windsor Locks facility is a 56 MW natural gas powered electrical and steam energy generating station 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 has entered into an agreement to extend the ESA with Ahlstrom from 2017 to 2027. As a result, APCo 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) 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 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.

(iv) 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. APCo reduced the amount of the APCo Credit Facility to \$120 million following the completion of the Senior Unsecured Debenture private placement by APCo in July 2011.

Liberty Utilities**(i) California Utility**

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 California Utility 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 California Utility, 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, as further described below under “*General Development of the Business – Three Year History and Significant Acquisitions – Fiscal 2012 – Liberty Utilities – Acquisition of Remaining Interest in California Utility*”.

(c) 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 have raised the growth profile for APUC’s earnings and cash flows which in turn supports an increase in the dividend to shareholders. As a result, on August 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 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 preferred shares have been assigned a rating of P-3 and Pfd-3(low) by Standard and Poor’s (“**S&P**”) and DBRS respectively. The proceeds of the offering were used primarily to partially fund the acquisition of the interest in the Gamesa wind powered generating stations (“**Gamesa Wind Facilities**”) which closed 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%.

As at December 31, 2012, Emera owned 34,903,750 Common Shares representing approximately 18.5% of the total outstanding Common Shares of APUC.

Subsequent to December 31, 2012 and pursuant to previously issued subscription receipts or commitments to subscribe for subscription receipts, APUC issued 2,614,005 Common Shares at a price of \$5.74 per share, 5,228,011 Common Shares at a price of \$5.74 per share and 3,421,000 Common Shares at a price representing \$4.72 per share pursuant to conversion of subscription receipts issued to Emera.

On March 26, 2013, Emera subscribed for and purchased 3,960,000 Common Shares of APUC at a price of \$7.40 per share for total proceeds of approximately \$29 million.

As a result of the transactions after December 31, 2012, Emera owns, as of March 26, 2013, 50,126,766 Common Shares, representing approximately 24.51% of the total 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.

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

On February 24, 2012 (“**Series 2A Redemption Date**”), APUC redeemed \$57.0 million, representing the remaining issued and outstanding, 6.35% convertible unsecured subordinated debentures due November 30, 2016 (“**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 of APUC.

(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 of APUC. 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 APUC common shares for the remaining \$0.9 million in Series 3 Debentures.

(vi) **APUC Credit Facility**

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

Liberty Utilities

(i) **Agreement to Acquire Georgia Utility**

On August 8, 2012, Liberty Utilities entered into an agreement with Atmos to acquire certain regulated natural gas distribution utility systems comprising of the Georgia Utility serving

approximately 64,000 connections located in the State of Georgia. The total purchase price for the Georgia Utility is approximately U.S. \$140.7 million representing a 1.1x premium to net assets for regulatory purposes of U.S. \$128.1 million and is subject to certain working capital and other closing adjustments.

On February 22, 2013, Liberty Utilities has received all federal and state regulatory approvals required to complete the acquisition. Closing is expected to occur on or about April 1, 2013 and will be reported as part of the Liberty Utilities (East) region.

(ii) **Acquisition of Remaining Interest in the California Utility**

On December 21, 2012, a subsidiary of APUC completed the acquisition of the remaining 49.999% ownership in California Pacific Utility Ventures LLC, which owns 100% of the California Utility assets. The subsidiary of APUC 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 Granite State Electric Utility and the EnergyNorth Gas Utility, both from National Grid, for consideration of U.S. \$285.0 million plus working capital and other closing adjustments for a total consideration of U.S. \$295.8 million. The purchase price for the utility assets represents a multiple of aggregate expected regulatory assets of approximately 1.14x. The regulated electric distribution company provides electric service to over 43,000 connections in 21 communities in New Hampshire and the regulated natural gas distribution utility provides natural gas service to over 87,000 connections in five counties and 30 communities in New Hampshire.

In the first half of 2013, Granite State Electric Utility will file a rate case with the New Hampshire Public Utilities Commission (“NHPUC”) seeking an increase in distribution base rates. The filing is based on a 2012 test year, with revenues and expenses reflecting known and measurable changes. The regulatory process associated with the rate case is expected to last one year, with temporary rates expected to be implemented on or about July 1, 2013 and the final permanent rates determined in the rate case going into effect on or about March 2014.

(iv) **Acquisition of Missouri Utility**

On August 1, 2012, Liberty Utilities completed the acquisition of regulated natural gas distribution utility systems (the “**Midwest Gas Utilities**”) 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.

The acquisition was originally announced in May 2011 and final regulatory approvals were received in June 2012. The purchase price for the utility assets represented a multiple of net assets for regulatory purposes of approximately 1.1x. Collectively, the regulated natural gas distribution systems provide natural gas service to approximately 82,000 connections.

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

In connection with the above noted gas and electric utility acquisitions during the third quarter, Liberty Utilities completed a U.S. \$225 million private placement debt financing. The financing was closed in two tranches contemporaneously with the closing of the New Hampshire and Missouri Utilities acquisitions. 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 Limited. Proceeds from the private placement were used to partially fund the New Hampshire and Midwest Gas Utilities acquisitions.

On March 14, 2013 Liberty Utilities completed a U.S. \$15 million private placement debt financing in connection with the acquisition of an Arkansas water utility. The notes are senior unsecured with a 10 year term and a coupon of 4.14%.

(vi) **Expansion of Liberty Utilities 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 will be 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 U.S. Wind Facilities**

In 2012 APCo completed its 60% equity investment in the Gamesa Wind Facilities which comprise of a portfolio of three wind powered generating stations (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) for consideration of \$271.7 million.

The Gamesa Wind 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 projects. Total cost of the three wind farms was approximately \$747 million.

The Gamesa Wind 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.

Total annual energy production is expected to be 1,352 GW-hrs per year. The Gamesa Wind 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, will be 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 for 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 Gamesa Wind Facilities.

(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. 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. The APCo Credit Facility now has a maturity date of November 16, 2015.

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

APCo has completed the repowering of the Windsor Locks facility’s electrical and steam energy generating station. The installation of a new 14 MW Solar Titan combustion gas turbine was completed 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) and is now fully operational. 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 now available as a peaking turbine to generate additional revenues.

2.3 Recent Developments – 2013

Corporate

(i) **Agreement with St. Leon Class B unit holders**

The St. Leon Facility is a 104 MW wind power generating facility which is owned by St. Leon LP. St. Leon LP had issued an aggregate of 100 Class B units, of which 18 units had been issued to each of Ian Robertson, currently the Chief Executive Officer of APUC and Chris Jarratt, currently the Vice Chair of APUC (the “**Senior Executives**”) and an aggregate of 64 units to third parties. APUC and the Class B unit holders (including the partnership owned by the Senior Executives) completed a transaction effective January 1, 2013 whereby the Class B units were exchanged for Series C preferred shares of APUC on a one-for-one basis. The characteristics of the Series C preferred shares will provide approximately the same after tax cash to individuals holding such shares as what was estimated to have been expected from the Class B units. The third parties and the partnerships owned by the Senior Executives who formerly held

the Class B units no longer hold Class B units in St Leon LP. The special committee of the Board retained the services of an independent advisor to review the historic financial performance of the St Leon facility, provide a valuation of the Class B units, provide estimation of distributions to Class B unit holders, and to provide advice to APUC in respect thereof.

Liberty Utilities

(i) Agreement to Acquire New England Utility

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 New England Gas Company (“**NEGasCo Acquisition**”) from Southern Union Company. New England Gas Company is a natural gas distribution utility serving over 50,000 customers in Massachusetts. The acquisition is subject to certain approvals and conditions, including state and federal regulatory approval, and is expected to close in the second half of 2013.

Total consideration for the utility asset purchase is approximately U.S. \$74 million, subject to working capital and closing adjustments representing a 1.0x premium to regulatory assets of \$73.9 million. The purchase price will be funded using a target capital structure of 52% equity and 48% debt and will include the assumption of U.S. \$19.5 million of existing debt.

(ii) Acquisition of Arkansas Utility

On February 1, 2013, Liberty Utilities completed the acquisition of issued and outstanding shares of United Water Arkansas Inc., a regulated water distribution utility (“**Pine Bluff Water Utility**”) from United Waterworks Inc. The Pine Bluff Water Utility is located in Pine Bluff, Arkansas and serves approximately 17,000 customers. Total purchase price for the Pine Bluff Water Utility was approximately U.S. \$27.6 million representing a 1.16x premium to net utility assets of U.S. \$24.6 million and subject to certain working capital and other closing adjustments. The Pine Bluff Water Utility will be included in the Liberty Utilities (Central) region.

(iii) U.S. \$100 million Acquisition Term Facility

On March 14, 2013 Liberty Utilities entered into a U.S. \$100 million term loan with a U.S. bank. The loan facility is available for acquisitions and general corporate purposes and matures on December 31, 2013.

APCo – Power Generation

(i) Acquisition of Shady Oaks Wind Facility

Effective January 1, 2013, APCo acquired the Shady Oaks wind facility, a 109.5 MW contracted wind powered generating station from Goldwind International SO Limited (“**Goldwind**”) for total consideration of approximately US\$148.9 million.

The Shady Oaks wind facility is located in Northern Illinois, approximately 80 km west of Chicago, Illinois and reached 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 an affiliate, Goldwind 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.

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

On March 14, 2013, APCo entered into an agreement to sell 10 small U.S. hydroelectric generating facilities that were no longer considered strategic to the ongoing operations of the Corporation for gross proceeds of U.S. \$27 million. The operating results from these facilities are therefore disclosed as discontinued operations on the consolidated statements of operations and prior periods have been reclassified to conform to this presentation.

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**

In Canada, the provinces have legislative authority over the supply of energy. The majority of the electrical supply within the Canadian provinces is provided by large Crown corporations such as Ontario Power Generation Inc. and Hydro-Québec or smaller, investor-owned utilities. These large utilities have been primarily responsible for the generation, transmission and distribution of electricity.

“**Green Power**” is considered electricity generated from renewable energy sources that do not contribute to greenhouse gas emissions. Green Power includes technologies such as small hydroelectric (generally defined as facilities of less than 20 MW in capacity), bioenergy, landfill gas, wind and photovoltaic technologies. Since 1997, both the federal and provincial governments in Canada have provided various incentives to stimulate the production of Green Power in Canada. The incentives have varied from direct subsidies, to tax credits to higher than market rates for electricity generated from renewable energy sources.

The ecoENERGY for Renewable Power is the most recent of a series of incentive programs created by the Canadian Federal government (previous programs were the Wind Power Production Incentive (WPPI) and the Renewable Power Production Incentive (RPPI)) that provides an incentive of one cent per kilowatt hour for up to 10 years to reduce the cost gap between new technologies and traditional sources of electricity. Eligible technologies include electricity generation from renewable energy sources such as wind, low-impact hydro, biomass, photovoltaic and geothermal energy. Although no new contribution agreements were signed after March 31, 2011, signed agreements will continue to receive payments as outlined in contribution agreements and up to March 31, 2021.

(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**”) and Public Utilities Regulatory Policies Act (“**PURPA**”).

a. **Rate Regulation**

Certain of APCo’s US Facilities are classified as qualifying facilities (“**QFs**”), under PURPA. While QFs were previously exempt from rate regulation under the FPA, due to changes in PURPA, QFs are now subject to rate regulation under Section 205 and 206 of the FPA, subject to certain exceptions. Sales of energy or capacity made by QFs 20 MW or smaller, or made pursuant to a contract executed on or before March 17, 2006, or made pursuant to a state regulatory authority’s implementation of PURPA are exempt from regulation under sections 205 and 206 of the FPA. All relevant APCo facilities had PPAs in place predating March 17, 2006, and as such have not been impacted.

The APCo facilities that are not QFs have market-based rate authority under the FPA and thus are subject to less regulation than cost of service based entities.

b. **PURPA Regulatory Structure**

The purpose of PURPA is to encourage the development of small independent power production. To accomplish this, FERC requires electric utilities to purchase energy and capacity from QFs at the utility’s avoided cost. “**Avoided Cost**” means costs a utility does not incur to add new generating capacity to the system by purchasing electricity from an independent or parallel generator.

As a result of the *Energy Policy Act of 2005*, electric utilities are no longer required to purchase energy or capacity from a QF if the utility can prove the QF has non-discriminatory access to:

- (1)(i) Independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy; and
- (ii) Wholesale markets for long-term sales of capacity and electric energy; or
- (2)(i) Transmission and interconnection services that are provided by a Commission-approved regional transmission entity and administered pursuant to an open access transmission tariff that affords non-discriminatory treatment to all customers; and
- (ii) Competitive wholesale markets that provide a meaningful opportunity to sell capacity, including long-term and short-term sales, and electric energy, including long-term, short-term and real-time sales, to buyers other than the utility to which the qualifying facility is interconnected. In determining whether a meaningful opportunity to sell exists, the Commission shall consider, among other factors, evidence of transactions within the relevant market; or
- (3) Wholesale markets for the sale of capacity and electric energy that are, at a minimum, of comparable competitive quality as markets described in paragraphs (a)(1) and (a)(2) of this section.

There is a rebuttable presumption that QFs have non-discriminatory access to the market if they are eligible for service under a Commission-approved open access transmission tariff (“OATT”) and are subject to Commission-approved interconnection rules. There is, however, also a rebuttable presumption that QFs with capacity at or below 20 MWs do not have non-discriminatory access to the market. Because all the APCo QFs have 20 MWs or less of capacity or are on a long term PPA, they qualify for this rebuttable presumption.

(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 which imposes an exclusive right and duty to serve in the service territory. A Certificate of Convenience and Necessity (“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 Federal Power Act, 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 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 APCo 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 APCo 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) (the “**EUA**”). The Power Pool of Alberta (the “**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 (the “**AESO**”) to operate and manage the Power Pool in a manner that promotes the fair, efficient and openly competitive exchange of electric energy in Alberta. The AESO is governed by an independent board appointed by the Alberta Minister of Energy.

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

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

(2) Ontario

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

The Ontario Electricity Financial Corporation (“**OEFC**”) holds all rights, obligations and liabilities under, and purchases the energy generated by the Ontario hydroelectric generating facilities in which APCo has an interest pursuant to, the existing contracts. APCo’s subsidiaries have also received a licence to generate from the OEB as required by the *Ontario Energy Board Act, 1998* (Ontario).

(3) New Brunswick and Northern Maine

In 2003 the New Brunswick government amended the provincial *Electricity Act (New Brunswick)* (the “**Electricity Act**”) which resulted in the start of competition in the generation business.

As a result of the Electricity Act, which took effect in October of 2004, New Brunswick Power Corporation (“**NB Power**”) was divided into separate businesses. The distribution and customer service division of NB Power now functions as a regulated monopoly and serves all the residential and industrial power consumers in the province, with the exception of those in Saint John, Edmundston and Perth-Andover which are served by Saint John Energy, City of Edmundston Electric and the Perth-Andover Electric Light Commission, respectively.

One of the separate entities created by the Electricity Act is the New Brunswick System Operator (“**NBSO**”), an independent not-for-profit statutory corporation. NBSO is responsible for the adequacy and reliability of the integrated electricity system, and for facilitating the development and operation of the New Brunswick electricity market. These responsibilities take the form of operation of the NBSO-controlled grid and administration of the Open Access Transmission Tariff and the New Brunswick Electricity Market Rules.

The NBSO is the Balancing Authority for New Brunswick, Prince Edward Island, and Northern Maine, and the Transmission Provider for New Brunswick. NBSO provides load following and regulation service to the system in order to supply customer load in the province while

maintaining scheduled flows on interconnections within established limits. NBSO is the authority responsible for the operation of the Bulk Power System in New Brunswick, Nova Scotia, Prince Edward Island, and a portion of northeastern Maine.

(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)* and corresponding regulations. The *Dam Safety Act (Quebec)* 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, APCo's Renewable Energy division was required to undertake technical assessments of eleven of the twelve hydroelectric facility dams owned or leased by APCo within the Province of Québec.

APCo has spent approximately \$1.7 million to date on dam safety evaluations, engineering, permitting and civil works related to the Bill C93 requirements. APCo currently estimates further capital expenditures of approximately \$16.9 million related to compliance with the legislation. It is anticipated that these expenditures will be invested over a period of several years approximately as follows:

	<u>Total</u>	<u>2013</u>	<u>2014</u>	<u>2015</u>	<u>2016</u>
Estimated future Bill C-93 Capital Expenditures	16,900	5,600	8,000	3,000	300

The majority of these capital costs are associated with the Donnacona, St. Alban, Belleterre, and Mont-Laurier facilities.

- The dam safety evaluation for the Mont Laurier facility was completed in 2008 and APCo's proposed remediation plan has now been accepted by the Quebec government. APCo has been performing engineering and permitting since 2010 and received the Certificate of Authorization from the Quebec government in November 2011. APCo completed the majority of the on-site remediation work in 2012 at a capital cost of approximately \$0.3 million. Phase two of the on-site remediation work is scheduled for Q3-Q4 of 2013 at an estimated cost of \$0.1 million.
- In respect of the Donnacona facility, APCo completed the dam safety evaluation in 2007 and has been investigating alternative engineering designs to minimize the cost of the remediation work. APCo is now pursuing a design that may result in a cost savings of 20% of the original estimates. APCo completed the engineering for this project in 2012 and submitted a final rehabilitation plan to the Quebec regulators as part of an application for a Certificate of Authorization. The remedial on-site work is anticipated to start in the summer of 2013 and be completed in 2014.

- The dam safety study for the St. Alban facility was completed in 2010 followed by a detailed condition assessment in 2011. APCo anticipates engineering and regulatory review to be completed in 2013, with remedial work performed in 2014 to 2015.
- APCo is presently reviewing options with respect to the Belleterre facility including the removal of several small dams that are not required for power generation. APCo has been corresponding with the Quebec government and other stakeholders about these options since 2007. APCo anticipates completion of any required work on these dams by 2015.
- Engineering for the Riviere-du-Loup facility was completed in fourth quarter of 2012. Following a geotechnical investigation the remediation work is now estimated at \$1.1 million.
- The dam remediation work related to Chute Ford was completed in 2012 while the work related to the St. Raphael facility is anticipated to be completed in 2013.

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 Rapids Facility

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

The Long Sault Rapids 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 venturers (the “**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, Algonquin Power (Long Sault) Corporation Inc. and Energy Acquisition (Long Sault) Ltd., are wholly-owned subsidiaries of Algonquin Power Corporation Inc. (“**APC**”), a corporation affiliated with APMI. The partners in the N-R Power Partnership are Nicholls Holdings Inc. and Radtke Holdings Inc., companies controlled by two independent businessmen. There are two non-recourse loans outstanding which are secured against the facility and the Co-Owners’ interest therein (see the subsection “*Credit Agreements*” below).

APCo’s interest in the Long Sault Rapids 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%. APCo 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. APCo 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 Long Sault Rapids 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 Long Sault Rapids 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 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 Long Sault Rapids 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 Long Sault Rapids 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 Long Sault Rapids Facility on their behalf for nominal consideration.

Credit Agreements

There is an outstanding senior loan against the Long Sault Rapids facility in the amount of \$38.1 million at December 31, 2012. 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 APCo 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, APCo issued an irrevocable letter of credit in an amount of \$1.2 million to replace the debt service escrow deposit. At December 31, 2012, the debt reserve was fully funded using the irrevocable letter of credit.

APMI Residual Ownership Interest

APCo's interest in the Long Sault Rapids facility is by way of subscribing to two notes from the original developers, which effectively entitles it to 100% of after tax cash flows of the facility up to 2013, 65% from 2014 to 2027 and 58% thereafter. APCo 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 APMI is one of the original partners in the Long Sault Rapids facility and is entitled to receive 5% of the equity cash flows commencing in 2014. Subsequent to December 31, 2012, APCo reached an agreement with the affiliate of APMI to acquire residual partnership interest in the Long Sault Rapids hydroelectric facility as part of an agreement to resolve a number of the historic business relationships between APCo and APMI. (See "*Business Associations with APMI and Senior Executives*").

(2) Côte Ste-Catherine Facility

The Côte Ste-Catherine 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 Côte Ste-Catherine 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 Québec 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 "*Legal Proceedings and Regulatory Actions – Legal Proceedings – Côte Ste-Catherine Water Lease Dues*".

(3) Mont Laurier Facility

The Mont Laurier facility is a 2.7 MW hydroelectric generating facility located on the Rivière-du-Lièvre in the Town of Mont Laurier, Québec. The 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 facility and Mont Laurier facility have PPAs 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 (Phase I) 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 facility is subject to a fixed annual escalation of 1.8%. The Côte Ste-Catherine 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 Facility

The Tinker 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 34.5 MW. Unit 5 of the Tinker Facility has been replaced with a new Kaplan variable pitch runner. Gross generation from the upgraded station is expected to be 140,000 MW-hrs per year. The Tinker Facility benefits from the flow regulation of the Squa Pan Facilities, both of which are also owned and operated by APCo.

As part of the generation assets in New Brunswick and Northern Maine, APCo owns and operates an electrical transmission system consisting of 14.7 km of 69 kV transmission line facilities. These facilities are used to interconnect the Tinker 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 transmission facilities are currently included in the Open Access Transmission Tariff of the NBSO.

The Tinker 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 Facility

The Dickson Dam Facility is located 20 kilometres 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 Dickson Dam Facility consists of three horizontal Francis type turbines and was commissioned into commercial operation on January 16, 1992. The facility is owned by APOT.

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

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

(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 market for APCo's Canadian wind facilities is Manitoba for the St. Leon, and St. Leon II Facilities, and Saskatchewan for the Red Lily Facility. The electricity generated by the wind turbines is transmitted via electrical collection lines to the facility substations' for subsequent delivery to the transmission system of the purchaser, Manitoba Hydro-Electric Board ("**Manitoba Hydro**") in the case of the St. Leon Facility and St. Leon II, and Saskatchewan Power Corporation ("**SaskPower**") in the case of the Red Lily I facility. The purchaser then distributes the electricity to its customers or to other endpoints via the grid.

In the US, the principal markets are the Regional Transmission Organizations ("**RTO**") of PJM Interconnection ("**PJM**") in the case of the Sandy Ridge, Shady Oaks, and Minonk Facilities and Electric Reliability Council of Texas ("**ERCOT**") in the case of the Senate Wind Facility. Similar to the situation in Canada, the US facilities transmit the wind turbine generated electricity via collection lines to facility substations which are then interconnected to the transmission system for distribution to customers.

(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.

The Manitoba government and Manitoba Hydro have independently undertaken studies to determine the potential of wind power generation in Manitoba. As a result of such studies, the Manitoba Government has advised it plans to have additional capacity of approximately 1,000 MW of wind power, to be constructed, using in part, independent power producers by 2014.

(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 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 part of this, 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 RTO's 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 Interconnection 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 RTO's operating in North America. ERCOT is the successor to the Texas Interconnect System (TIS) 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 Facility

The St. Leon 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.

In January 2010, APCo 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 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 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 and as at December 31, 2012, 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 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. APCo anticipates that the facility will earn WPPI of approximately \$3.0 million annually based on the current estimated long term wind resource.

(2) St. Leon II Facility

The St. Leon II Facility is a 16.5 MW wind energy facility located near St. Leon, Manitoba, 150 km southwest of Winnipeg, adjacent to the St. Leon Facility.

In July 2011, an affiliate of APCo executed a 25-year PPA with Manitoba Hydro in respect of the St. Leon II Facility. Construction of the St. Leon II Facility was completed in the first quarter of 2012 for a total capital cost of \$29.3 million. Beginning July 1, 2012, the facility is 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 St. Leon II for approximately 20 years.

St. Leon II Wind Energy 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 Facility is sold to Manitoba Hydro. As of December 1, 2012, the St. Leon II Facility achieved commercial operation status under the PPA with 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 LP's option. Under the terms of the PPA, operational security in an amount of about \$300,000 is required through 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 facility ("**Red Lily I**") is a 26.4 MW wind generation facility located 5 kilometres west of Moosomin, Saskatchewan. Red Lily I consists of 16 Vestas V82 wind turbine generators. The equity in Red Lily I 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, 2012, the APCo 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. APCo 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, APCo is entitled to certain supervisory fees.

In January 2010, 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 Facility for approximately 20 years.

On July 30, 2008, the owner of Red Lily I 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 the counties of Lee and Brooklyn, Illinois, 80 km west of Chicago. The Shady Oaks wind facility is owned by GSG 6, LLC, an entity acquired by Algonquin Power Co. from Goldwind International SO Limited ("**Goldwind**") on January 1, 2013.

The Shady Oaks wind facility 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.

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, under which 85% of the electricity produced at the Shady Oaks wind facility and related credits created from the generation of that electricity are sold to Commonwealth Edison. 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 PPA, security in an amount of US\$4.7 million is required. That obligation is being maintained by Goldwind utilizing an irrevocable letter of credit with an associated fee being assessed to Algonquin Power Co.

As at the acquisition date of January 1, 2013, the Shady Oaks wind facility has an outstanding credit facility with the China Development Bank Corporation in the amount of US \$150.0 million. The current portions of the facility of U.S. \$25.0 million and U.S. \$3.0 million are payable on June 30 and November 15, 2013, respectively. The semi-annual principal repayment schedule for the following 11 years ranges from \$3.0 million to \$6.0 million with a final repayment of U.S. \$20 million in 2025. This debt may be repaid in whole or in part at any time without penalty and bears interest at Libor plus 280 basis points.

(5) Sandy Ridge Wind Facility

The Sandy Ridge wind facility is a 50 MW wind energy facility located near Tyrone, PA, 180 km east of Pittsburgh, PA. The Sandy Ridge wind facility is owned by Sandy Ridge Wind, LLC, in which APCo holds an indirect 60% equity interest.

As part of the acquisition of the majority interest in Sandy Ridge Wind, LLC, an Asset Management and Balance of Plant Operations and Service Agreement (“**AMBOSA**”) was executed between the facility and Gamesa USA, the operating company for the original equipment manufacturer, in March 2012. Under the AMBOSA the service company provides asset management and balance of plant operations to the owner for a period of 20 years. Asset management services include overseeing an Operations and Maintenance Agreement between the owner and Gamesa Wind US LLC 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.

The Sandy Ridge wind facility is party to a long term energy production hedge (“**Energy Production Hedge**”) with J.P. Morgan Energy Ventures Corporation (“**JPMVEC**”), the wholly owned subsidiary of J.P. Morgan. The life of the commitment is 10 years. Based on the JPMVEC contract quantity, approximately 72% of energy revenues are expected to be earned under the Energy Production Hedge. All energy produced in excess of that included in the Energy Production Hedge, together with ancillary services including capacity and renewable energy credits, is sold into the energy market in which the Sandy Ridge wind facility is located.

(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, in which APCo holds an indirect 60% equity interest.

As part of the acquisition of the majority interest in Minonk Wind, LLC, an AMBOSA was executed between the facility and Gamesa USA, the operating company for the original equipment manufacturer, in March 2012. Under the AMBOSA the service company provides asset management and balance of plant operations to the owner for a period of 20 years. Asset management services include overseeing an Operations and Maintenance Agreement between the owner and Gamesa Wind US LLC 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.

The Minonk wind facility is party to an Energy Production Hedge with JPMVEC. The life of the commitment is 10 years. Based on the JPMVEC contract quantity, approximately 73% of energy revenues are expected to be earned under the Energy Production Hedge. All energy produced in excess of that included in the Energy Production Hedge, together with ancillary services including capacity and renewable energy credits, is sold into the energy market in which the facility is located.

(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, in which APCo holds an indirect 60% equity interest.

As part of the acquisition of the majority interest in Senate Wind, LLC, an AMBOSA was executed between the facility and Gamesa USA, the operating company for the original equipment manufacturer, in March 2012. Under the AMBOSA the service company provides asset management and balance of plant operations to the owner for a period of 20 years. Asset management services include overseeing an Operations and Maintenance Agreement between the owner and Gamesa Wind US LLC 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.

The Senate wind facility is party to an Energy Production Hedge with JPMVEC. The life of the commitment is 15 years. Based on the JPMVEC contract quantity, approximately 64% of energy revenues are expected to be earned under the Energy Production Hedge. All energy produced in excess of that included in the Energy Production Hedge, together with ancillary services including capacity and renewable energy credits, is sold into the energy market in which the facility is located.

(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 land fill. 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 station located in Brampton, Ontario which produces electricity from incinerating non-recyclable materials, including municipal solid waste. The facility is designed to incinerate over 500 tonnes per day of municipal solid waste from five incinerators. The EFW Facility generates approximately 60,000 pounds per hour of steam in excess of requirements for production of internally consumed electricity. It is owned by APEFW which forms part of the APCo ownership chain.

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 the Region of Peel concluded. APCo has now entered into several waste supply agreements with both municipal and commercial entities to ensure continued operation of the facility. In addition, APCo has entered into several agreements to market the EFW capacity in various commercial waste sectors, including specialty wastes and product destruction.

The majority of the EFW steam is diverted to the BCI Facility. See “*Description of the business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Thermal – Cogeneration – Material Facilities – BCI 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.

The EFW Facility is selling electricity at the Hourly Ontario Energy Price (“**HOEP**”). The HOEP is the hourly price that is charged to local distribution companies, other non-dispatchable loads and self-scheduling generators. APCo is currently negotiating with the Ontario Power Authority to enter into a new long term contract for the power output from the EFW Facility.

(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 APCo'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. A summary of the contracts for the cogeneration facilities is attached in Schedule B. 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 Energy Commission and FERC. The California Independent System Operator administers the wholesale electricity market place for the region.

(2) Connecticut

Connecticut Light and Power Company ("CL&P") is part of the North East Utilities System which is located in the New England Power Pool. The Independent System Operator New England ("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. Electricity products including energy, capacity and ancillary services are bid, scheduled, bought, and sold by market participants on an internet-based market system.

(iii) **Material Facilities**

(1) Sanger Facility

The Sanger facility is a 56MW natural gas-fired generating facility located in Sanger, California. The Sanger 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, APCo successfully completed a major outage at the Sanger 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 facility is owned by Algonquin Power Sanger LLC, a subsidiary of APFA.

Output of the Sanger facility is governed by the terms and conditions of a firm capacity and energy PPA with Pacific Gas & Electric Company (“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 Sanger 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 Sanger 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 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 facility in the amount of US \$19.2 million as at December 31, 2012. The loan is a California Pollution Control Finance Authority Variable Rate Demand Resource Recovery Revenue Bond, due September 1, 2020. The senior loan bears interest at variable rates, reset monthly. Interest is payable monthly with no principal repayments. The effective interest rate in 2012 was 2.29%. The loan is secured solely by the Sanger facility, the ownership interests therein and an irrevocable letter of credit in an amount of US \$19.5 million.

(2) Windsor Locks Facility

APCo has completed the repowering of the Windsor Locks facility’s electrical and steam energy generating station. The installation of a new 14 MW Solar Titan combustion gas turbine was completed in July 2012 at a total capital cost of U.S. \$19.3 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 APCo also 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 now available as a peaking turbine to generate additional revenues.

With the repowering complete the Windsor Locks facility has a total installed capacity of 70 MW. The Windsor Locks facility is a combined cycle generating station comprised of a 56 MW General Electric natural gas fired turbine and a 14 MW General Electric steam turbine both commissioned in 1990 and a Solar Titan 130 combustion turbine installed in 2012. The Windsor Locks facility is owned by Algonquin Power Windsor Locks LLC.

The Windsor Locks 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 Facility for use at its specialty fibers composites mill located adjacent to the Facility. APCo has entered into an extension of the ESA with Ahlstrom, the extended term continues until 2027. Payments under the ESA are fully indexed to the cost of natural gas consumed by the Windsor Locks facility.

With the current configuration 90% of the output of the baseload electrical generation is generated by the Solar Titan 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. APCo's AES group manages the off-take sales from this Facility into the ISO-NE market.

Natural gas for the Windsor Locks facility is delivered to the facility under gas distribution agreements with Yankee Gas Service Company ("**Yankee Gas**"). APCo's subsidiary, Windsor LLC, has entered into an agreement with a natural gas retailer and wholesale supplier to provide gas to the Windsor Locks facility as required to meet the Ahlstrom ESA obligations and the market dispatch requirements.

(3) BCI Facility

The BCI 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 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.

(4) Kirkland Facility

The Kirkland facility is a 132MW combined cycle integrated fuels generation station 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 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 facility is sold to OEFC pursuant to a 40 year contract, which expires in 2030. Natural gas used by the 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 Kirkland 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. Currently, 75% of the operating income of the Facility is paid to Northland under the management agreement.

(5) Cochrane Facility

The Cochrane facility is a 40MW combined cycle integrated fuels generating station located in the Town of Cochrane, Ontario. The Cochrane 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 facility was commissioned in 1990 and is currently managed by Northland. Electricity produced by the Cochrane 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 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 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.

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

The primary business of AES is to market the output of APCo owned assets which would otherwise sell the energy they generate on a merchant basis. AES also works to develop strategies for selling the power output of APCo facilities that are approaching the end of their PPAs and to engage, where possible, in the negotiation of new contracts that would otherwise sell power on a merchant basis. In addition to traditional wholesale power marketing functions,

AES provides standard offer retail contracts and direct customer retail 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 Maine and New Brunswick markets. AES purchases energy from the Tinker Facility, based on historical long term average levels of hydroelectric energy generation, the Tinker 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 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 Gamesa Wind Facilities and Shady Oaks wind facility. These wind facilities, located in the PJM and ERCOT markets, are accompanied by long term hedge or power purchase agreements 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 purchase agreements.

(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. 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.

APCo'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 APCo will begin construction.

(ii) Principal Market Environment

APCo believes that future opportunities for power generation projects will continue to set targets 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. Nova Scotia also continues to offer its Community Feed-in-Tariff (“ComFIT”) 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 and British Columbia continues to offer its Standard Offer Program (“SOP”) for renewable projects under 15 MW.

Within the United States, the most notable stimulus for the development of renewable power emanates from the American Recovery and Reinvestment Plan (ARRP) of 2009. The ARRP offers Investment Tax Credits (“ITCs”) based upon a percentage of eligible capital costs, or Production Tax Credits (“PTCs”) of \$22 per MW hour for wind for the first ten years of production. However additional incentives continue to be offered independently for the development of renewable sources of power at the state and local levels.

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

(iii) Current Development Projects

APCo’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:

<u>Project Name</u>	<u>Location</u>	<u>Size (MW)</u>	<u>Estimated Capital Cost</u>	<u>Commercial Operation</u>	<u>PPA Term</u>	<u>Production GW-hrs</u>
Chaplin Wind ¹	Saskatchewan	177	\$ 355.0	2016	25	720.0
Amherst Island ²	Ontario	75	\$ 230.0	2015	20	247.0
Morse Wind ^{3,4}	Saskatchewan	25	\$ 70.0	2014	20	93.0
Val Eo ¹	Quebec	24	\$ 70.0	2015	20	66.0
St. Damase ¹	Quebec	24	\$ 66.0	2014	20	78.7
Cornwall Solar ^{1,2}	Ontario	<u>10</u>	<u>\$ 45.0</u>	2013	20	<u>13.4</u>
Total		<u>335</u>	<u>\$ 836.0</u>			<u>1,218.1</u>

1 PPA signed

2 FIT contract awarded

3 Two 10 MW PPAs; one 5 MW 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”).

(1) Chaplin Wind

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, 200 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 \$355 million and consist of approximately 77 multi-megawatt wind turbines. The project is expected to generate first full year EBITDA of \$37.5 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 a favourable interconnection location by interconnecting with SaskPower’s new

P1S 230 kV transmission line from Swift Current to Moose Jaw and will be compliant with SaskPower's latest interconnection requirements.

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(2) Amherst Island Wind

The Amherst Island Wind Project is located on Amherst Island in the village of Stella, approximately 25 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 FIT contract originally stated that the OPA had the option to terminate the FIT contract prior to the date that the OPA had issued a Notice to Proceed ("NTP") and APCo had paid the incremental security required by the NTP. On August 2, 2011, the Ontario Ministry of Energy directed the OPA to offer FIT contract holders the opportunity to have the OPA's pre-NTP termination rights under the FIT contract waived. APCo exercised this option on August 9, 2011. As required by the waiver, APCo submitted a domestic content plan on October 14, 2011 and provided a statutory declaration regarding equipment supply commitments by November 30, 2011.

The Amherst Island wind project is currently contemplated to use efficient 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 final open-house for public consultation was conducted on March 5th and 6th, 2013. The submission of the Renewable Energy Approval application subsequent to the open house is targeted for April 2013. Construction will commence shortly following the approval of the application and is expected to take 12 to 18 months.

(3) Morse Wind Project

The Morse wind project is comprised of three contiguous projects with 25 MW in aggregate installed generating capacity. The Morse wind 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.

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 two 10 MW projects were awarded in May 2010 and the 5 MW project was awarded in June 2011. The execution of the PPA pursuant to this program is expected to take place concurrently with the execution of the Interconnection Agreement in late March of 2013. The Environmental Impact Assessment was submitted for the project in mid-2012 and as a result the project was deemed "not a development". This allows the project to proceed towards the construction phase without the requirement for a full Environmental Assessment. The expected date of operation for the projects is in early 2015.

The total annual energy production for the Morse wind project is estimated to be 93,000 MWhr. The capital cost to construct the Morse wind project is currently estimated to be \$65-\$70 million, inclusive of acquisition costs. The first year PPA rate is set at \$101.98 per MWhr for the first full year of operations, which APCo expects to occur in 2014, with an annual escalation provision of 2% over the expected 20 year term.

(4) 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 la Matapédia. The project proponents include the Municipality of Saint-Damase and APCo. At the request of the turbine manufacturer, the project has recently gone through a turbine model change, changing from the originally proposed 8 wind turbines (E-101) of 3 MW each to 10 wind turbines (E-92) of 2.35 MW each. The annual energy production is estimated at 78,700 MW-hrs with a total installed capacity of 23.5 MW for the first phase. The second phase of the project would entail the development of an additional 106 MW's. The permitting and the environmental impact assessment are ongoing and the construction of the first project phase is to begin in the fall of 2013. Commercial operations are expected to commence in late 2014.

APCo's interest in the project will not be less than 50%. Final funding of the project will be arranged and announced when all required permitting has been met, and all other pre-construction conditions have been satisfied. Preliminary permitting began in early 2011 and community consultations were conducted in July 2011, March 2012 and September 2012. The project's social acceptance is strong and there will be no requirement for a public hearing under the auspices of the BAPE. The environmental impact assessment for the project has also been submitted and is under review with provincial ministerial approval anticipated for the third quarter of 2013.

Val-Éo

Phase one of the Val-Éo wind project is located in the local municipality of Saint-Gideon de Grandson, 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 66,000 MW-hr annually. Construction of the first 24 MW phase of the project is expected to begin in the fall of 2014 with commercial operations commencing in late 2015. . The second phase of the project would entail the development of an additional 106 MW's.

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 25%. Final funding of the project will be arranged and announced when all required permitting has been secured, and all other pre-construction conditions have been satisfied. Preliminary permitting began in early 2011 and studies of flora and fauna and the public consultation process are ongoing. The submission of the environmental impact study to the Minister of Sustainable Development, Environment, Wildlife and Parks is targeted for the second quarter of 2013.

(5) Cornwall Solar

In the first quarter of 2012, APCo acquired 62.5% of the issued and outstanding shares of Cornwall Solar Inc. (“**Cornwall Solar**”), which owns the rights to develop a 10 MWac solar project located near Cornwall, Ontario (the “**Cornwall Project**”). In addition to the Cornwall Project, APCo has acquired an option to acquire ten additional Ontario based solar projects. APCo has submitted FIT applications for an additional 100MWac.

The Cornwall Project has been granted an Ontario 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 project received its Renewable Energy Approval on January 15th, 2013, and construction of the project is expected to begin in the second quarter of this year. The project’s environmental assessment has now been deemed “administratively complete”. Commercial operation is estimated in late 2013 with expected annual generation of approximately 13,400 MW-hrs.

Total capital cost of the project is targeted at approximately \$45 million, including the consideration to be paid for the acquisition of the project. Funding for the project will be arranged and announced when all required permitting and all other pre-construction conditions have been satisfied.

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

Algonquin 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 facilities 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 plants are located in the United States of America and currently owns utilities operating in the states of Arizona, Texas, Missouri and, as of February 1, 2013, 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 (ADH) has the 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 Facility

The Gold Canyon facility is a wastewater treatment facility established in 1984 to serve a number of residential developments and in an unincorporated area of Pinal County referred to as Gold Canyon, approximately 25 miles east of downtown Phoenix, Arizona. The Gold Canyon facility currently serves over 7,500 residential and commercial connections. Gold Canyon facility is owned by a wholly-owned subsidiary in the Liberty Utilities (West) region.

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 facility is a consumptive re-use facility and sells its reclaimed A+ effluent for use as irrigation water on two neighbouring 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) Litchfield Park Facility

The Litchfield Park facility is a water distribution and wastewater treatment facility 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 Litchfield Park facility is owned by a wholly-owned subsidiary of the Liberty Utilities (West) region.

The Litchfield Park facility presently serves approximately 17,600 water and 19,500 wastewater connections. The wastewater facility has permitted capacity of 4.1 million gpd. The Litchfield Park facility's water infrastructure 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 Litchfield Park facility 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 5.1MGD from 4.1MGD. The Litchfield Park facility now operates at approximately 70% of design capacity. The Litchfield Park facility supplies Class "A+" effluent to a number of local golf courses in the area.

On February 28, 2013, Liberty Utilities (West) filed a general rate case with the Arizona Corporation Commission related to the Litchfield Park Service Company facilities 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. The request contemplates a December 31, 2012 test year with new rates are expected to be implemented in the first half of 2014.

The Litchfield Park facility 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, 2012 of U.S. \$3.4 million bearing interest at rates between 5.95%. The second series was issued in 2001 with a principal amount as of December 31, 2012 of U.S. \$7.0 million and bearing interest at rates between 6.75%. As partial security for these bonds, the Facility is required to hold funds in a restricted, interest bearing, investment account. The balance of this account at December 31, 2012 was U.S. \$1.2 million.

(3) Rio Rico Facility

The Rio Rico facility is a water distribution and wastewater facility located in Santa Cruz County, Arizona approximately 60 miles south of Tucson, Arizona. The Rio Rico facility serves approximately 6,700 water and 2,200 wastewater connections in the community of Rio Rico, Arizona. The Rio Rico facility is owned by a wholly-owned subsidiary of Liberty Utilities (West).

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

On May 31, 2012, Liberty Utilities (West) filed a general rate case with the Arizona Corporation Commission related to the Rio Rico facility seeking, among other things, an increase in EBITDA by U.S. \$1.0 million over 2011 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 a mechanism that helps mitigate the effects of

regulatory lag on capital investment. The request contemplates a February 29, 2012 test year for its water and wastewater divisions. The next step in the regulatory process is a hearing in March 2013 with new rates expected in Q3 2013.

(4) Pine Bluff Facility

Following the completion of the acquisition on February 1, 2013, 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 17,000 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 would include 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 its 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 California Utility 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 California Utility 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.

(2) New Hampshire

The NHPUC is vested with general jurisdiction over electric, telecommunications, natural gas, water and sewer utilities as defined in RSA 362:2 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. Electric distribution companies are also required to provide electric 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) California Utility

The California Utility provides electric distribution service to the Lake Tahoe basin and surrounding areas. The service territory, centered around a highly popular tourist destination, has a primarily residential and small commercial customer base spread throughout Alpine, El Dorado, Mono, Nevada, Placer, Plumas and Sierra Counties in northeastern California. The utility plant is comprised of approximately 94 miles of high voltage distribution lines, 13 substations, and 39 distribution circuits (14.4 kV) serving just over 47,000 connections in the seven County service territories. The connection base is heavily-weighted towards El Dorado and Placer Counties, which counties comprise approximately 89% of total revenues.

On December 21, 2012, APUC completed the acquisition of the remaining 49.999% ownership in CPUV, which owns 100% of the California Utility assets. APUC 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. 4,790,000 of these shares were issued on December 27, 2012, and the remaining 3,421,000 shares were issued on February 14, 2013.

Connection Base

The California Utility'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 with no single connection accounting for more than 3.6% of annual sales volume.

Rate Case

The California Utility'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 \$3.747 million in 2013; a test year rate base of \$121.206 million; a 2013 return on equity of 9.875%, based upon a capital structure of 48.5% debt and 51.5% equity, using a long-term debt cost of 5.54% and resulting in an overall rate of return of 7.75%. 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 California Utility 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 California Utility'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 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 California Utility 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 California Utility 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.

PPA

The California Utility 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 California Utility 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 ("RPS") requirements, and the PPA is designed to enable the California Utility to comply with the associated RPS reporting requirements.

Financing

The California Utility 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 Utility

Granite State Electric Utility provides distribution service to approximately 43,000 connections in 21 communities located in 2 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 Corporation'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

Granite State Electric Utility's customer base consists of a mixture of residential, commercial and industrial customers with residential customers representing approximately 35,500 of its 43,000 connections. The Corporation's approximate 7,500 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 Ivy League educational institution.

Rate Case

In the first half of 2013, Granite State Electric Utility expects to file a rate case with the NHPUC seeking an increase in distribution base rates. The filing is based on a 2012 test year, with revenues and expenses adjusted to reflect known and measurable changes. In addition, Granite State Electric Utility will request approval to implement a “rate year” step adjustment to reflect certain capital additions to rate base after the test year. Among other things, Granite State Electric Utility will also seek to continue current cost-recovery tracking mechanisms, including long-term continuation of the REP/VMP Program and a modification to allow for recovery of pre-staging personnel and equipment for qualifying storms. The case is expected to last one year, with temporary rates expected to be implemented on or about July 1, 2013, permanent rates in or about March 2014, and a step-adjustment sometime thereafter.

Pursuant to a 2007 Settlement Agreement (“**2007 Settlement Agreement**”) approved by the NHPUC, Granite State Electric Utility maintains an authorized 50% debt, 50% equity capital structure and a 9.67% authorized return on equity (“**ROE**”). According to the terms of the 2007 Settlement Agreement, Granite State Electric Utility may earn up to 11% before earnings must be shared on a 50-50 basis with customers. Granite State Electric Utility had been earning in excess of its allowed rate of return prior to the 2007 Settlement Agreement. In addition, the 2007 Settlement Agreement provided for a \$2.2 million reduction in Granite State Electric Utility’s distribution rates reflecting, among other things, an adjustment to offset historical over-earning in two steps: the first step, a \$1.1 million reduction, became effective August 2007, and the second step, a \$1.1 million reduction, became effective January 2008. The 2007 Settlement Agreement also established a five-year distribution rate plan effective January 1, 2008 through December 31, 2012 (the “**Rate Plan**”), during which distribution rates were frozen except for rate adjustments in the event of certain uncontrollable exogenous events, catastrophic financial events, adjustments to the Storm Fund and moderate annual rate adjustments related to the Corporation’s Reliability Enhancement and Vegetation Management Plans Report and Reconciliation (“**REP/VMP**”). The 2007 Settlement Agreement does not prohibit the Corporation from proposing to adjust fees and other charges for new services under its tariff that are subject to Commission approval. Since that time, Granite State Electric Utility has continued to invest in plant as well as its annual investments in the REP/VMP plans. Due in part to the effects of the \$2.2 million decrease, the downturn in the US economy, continued investments in the business and rising operating costs, the Corporation’s return has suffered in recent years. Therefore, on February 27, 2013 Granite State Electric Utility filed a notice of intent with the NHPUC indicating its plans to file a distribution rate case on March 29, 2013 requesting an increase of \$15.2 million in general rates, based on an historic test year of 2012. The requested increase consists of several components; a temporary increase in rates beginning in July 2013, a step increase for investments made in 2013 after the original 2012 test year and the overall rate increase. Under NH law, the NHPUC has one year from the date of filing to make its final ruling on the requested increase.

Default Service Adjustment Provision

Granite State Electric Utility 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 Utility is required to participate in the ISO-NE market and abide by its rules under FERC. Granite State Electric Utility 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 Corporation 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

Granite State Electric Utility 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, offer system operators flexibility in moving the gas from point to point. The interstate pipeline companies are regulated by the Federal Energy Regulatory Commission. 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 in 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 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, EnergyNorth Gas Utility is regulated by the NHPUC. The NHPUC is vested with general jurisdiction over electric, telecommunications, natural gas, water and sewer utilities as defined in RSA 362:2 for issues such as rates, quality of service, finance, accounting, and safety.

Natural gas bills can be broken down into two primary components, delivery and commodity. The **delivery** charges cover costs associated with the delivery of gas supply through EnergyNorth Gas Utility's pipelines (i.e., gas distribution 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 EnergyNorth Gas Utility's plant investment. It is through the allowed rate of return on plant investment that EnergyNorth Gas Utility's has the opportunity to earn a return.

The commodity charge is for gas supply purchased by Energy North 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. EnergyNorth Gas Utility 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.

(iii) **Material Facilities**

(1) EnergyNorth Gas Utility

EnergyNorth Gas Utility is a regulated natural gas utility providing natural gas distribution services to approximately 87,700 connections in 30 communities covering five counties in New Hampshire. Its franchise service area includes the communities of Nashua, Manchester and Concord, NH. EnergyNorth Gas Utility 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

EnergyNorth Gas Utility serves approximately 87,700 connections in New Hampshire with a mix of residential, commercial, industrial and transportation customers. Of its 87,700 connections, approximately 76,400 are residential connections, while 11,300 are commercial and industrial connections. The Commercial and Industrial connection base is a diversified mix of retail, medical, education and industrial uses. No one connection represents more than 3% of its connection base.

Rate Case

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

(2) Midwest Gas Utilities

Midwest Gas Utilities are regulated natural gas utilities providing natural gas distribution services to approximately 83,504 connections in 190 communities in the states of Illinois, Iowa and Missouri. Its 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 Midwest Gas Utilities have 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

Midwest Gas Utilities serve approximately 22,755 connections in Illinois, 4,430 connections in Iowa and 56,319 connections in Missouri with a mix of residential, commercial, industrial and transportation customers. Of its 83,504 connections, approximately 76,816 (92%) are residential connections, while 6,688 (8%) 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

The state of Illinois allows full recovery of all gas costs (including commodity price, transportation, reservation and demand costs, hedging costs, storage costs). Rate is adjusted monthly with an annual reconciliation based on the calendar year.

The state of Iowa allows full recovery of all gas costs ((including commodity price, transportation, reservation and demand costs, hedging costs, storage costs). Rate is adjusted monthly with an annual reconciliation based on the 12 months ended August of each year.

The state of Missouri allows full recovery of all gas costs (including commodity price, transportation, reservation and demand costs, hedging costs, storage costs). 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.

3.3 Business Associations with APMI and Senior Executives

There have been a number of business relationships between the Senior Executives (Ian Robertson and Chris Jarratt), APMI (a company in which the Senior Executives have an interest) and related affiliates (collectively the “**Parties**”) and APUC. These relationships include joint ownership of certain generating facility assets, business relationships between the parties and payment of fees associated with previous transactions. In 2011, the Board initiated a process to review all of the remaining business associations with the Parties in order to reduce, streamline and simplify these relationships. The Board formed a special committee and engaged independent consultants to assist with this process.

The co-owned assets and remaining business associations as at December 31, 2012 are listed below. During the quarter ended March 31, 2012, APUC and the Parties reached an agreement to resolve a number of the business associations and relationships (the “**Agreement**”). The transaction is subject to finalization of definitive agreements which are expected to be completed in the first quarter of 2013. A more detailed description of the Agreement has been set out below in Settlement of Other Business Associations.

Rattlebrook hydroelectric generating facility

Rattlebrook is a 4 MW hydroelectric generating station owned 45% by APUC, 27.5% by Senior Executives and the remaining percentage by third parties. This relationship was addressed pursuant to the Agreement. See “*Settlement of Other Business Associations*” below for more details.

Brampton Cogeneration Inc.

BCI is an energy supply facility which sells steam produced from APCo’s EFW facility. APMI maintains a carried interest equal to 50% of the annual returns on the project greater than 15%. No amounts have ever been paid under this carried interest. In 2008, APMI earned a construction supervision fee of \$0.1 million in relation to the development of this project which has been accrued. This relationship was addressed pursuant to the Agreement.

Long Sault Rapids hydroelectric generating facility

Long Sault is a hydroelectric generating facility in which APUC acquired its interest in the facility by way of subscribing to two notes from the original developers. An affiliate of APMI is one of the original partners in the facility and is entitled to receive 5% of the equity cash flows commencing in 2014. This relationship was addressed pursuant to the Agreement.

Chartered aircraft

APUC utilizes chartered aircraft owned by an affiliate of APMI. At December 31, 2012, the remaining amount of the advance was \$nil (December 31, 2011 – \$0.3 million).

Office lease

APUC has leased its head office facilities on a triple net basis from an entity partially owned by Senior Executives. The lease expires on December 31, 2015.

Operations services

APUC has historically provided supervisory management on a cost recovery basis for one small hydro facility in which Senior Executives hold an indirect equity interest. The board has agreed to extend the existing relationship pursuant to an agreement that can be terminated by either party upon 30 days written notice until December 31, 2013.

Sanger construction management

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. An amount of U.S. \$0.6 million has been accrued as an estimate of the final fee owed to APMI. This was settled pursuant to the Agreement.

Clean Power Income Fund

During 2007, Algonquin allowed its offer to acquire Clean Power Income Fund (“**Clean Power**”) to expire and earned a termination fee of \$1.8 million. As part of its role in the process, APUC has agreed to pay APMI a fee of \$0.1 million. As of December 31, 2011 this amount is accrued and included in accounts payable on the consolidated balance sheet. This was settled pursuant to the Agreement.

Red Lily I

APMI was an early developer of the 26 MW Red Lily I wind power generation facility. As such it is entitled to a royalty fee based on a percentage of operating revenue and a development fee from Red Lily I. This relationship was settled pursuant to the Agreement.

Trafalgar

APCo owns debt on seven hydroelectric facilities owned by Trafalgar Power Inc. and an affiliate (“**Trafalgar**”). In 1997, an affiliate of APMI moved to foreclose on the assets, and subsequently Trafalgar went into bankruptcy. Trafalgar was previously awarded a U.S. \$10.0 million claim in respect of a lawsuit related to faulty engineering in the design of these facilities, and these funds are held in the bankruptcy estate. As previously disclosed, Trafalgar, APUC and an affiliate of APMI are involved in litigation over, among other things, a civil proceeding on the foreclosure on the assets and in bankruptcy proceedings. APMI funded the initial \$2 million in legal fees. An agreement was reached in 2004 between APMI and APUC whereby APUC would reimburse APMI 50% of the legal costs to date in an amount of approximately \$1 million, and going forward APUC would fund the legal fees, third party costs and other liabilities with the proceeds from the lawsuits being shared after reimbursement of legal fees, third party costs and other liabilities. The Board has determined that any proceeds from the lawsuit will be shared between APMI and APUC proportionally to the quantum of such costs funded by each party.

Settlement of Other Business Associations

During the quarter ended March 31, 2012, APUC and the Parties (the Senior Executives, APMI and related affiliates) reached the Agreement to resolve a number of the historic joint business associations between APUC and the Parties. The Agreement is based on an effective date of January 1, 2012 and the transaction is subject to finalization of definitive agreements which are expected to be completed in the first quarter of 2013.

Under the Agreement, APUC will exchange its 45% interest in the 4MW Rattlebrook hydroelectric facility (including a \$0.5 million positive working capital adjustment) in return for the Parties’ residual partnership interest in the Long Sault Rapids hydroelectric facility and the equity interest in the Brampton cogeneration plant. The agreement also terminates outstanding fees potentially owing to APMI in respect of the following: the historic transactions including the Sanger repowering project, the offer to acquire Clean Power Income Fund and the development of the Red Lily I wind project.

The special committee of the Board retained the services of an independent advisor to review the historic financial performance of the Rattlebrook and Long Sault Rapids facilities, provide a valuation of these assets and to provide advice to APUC in respect thereof.

3.4 Principal Revenue Sources

As at March 31, 2013, APUC owned, directly or indirectly, debt, equity and royalty and other interests in 44 renewable generation facilities and 10 thermal generation facilities including those identified in “*Corporate Structure – Intercompany Relationships – Other Interests in Energy Related Developments*”, two electrical distribution facilities, four natural gas distribution

utilities and 22 water distribution and wastewater facilities. For the year ended December 31, 2012, APUC derived approximately 32.8% of its revenues from its interests in power generation facilities (47.4% in 2011), 3.9% of its revenues from waste disposal fees (6.1% in 2011), 29.3% of its revenues from electrical distribution utilities (28.6% in 2011), 12.6% of its revenues from its interests in water distribution and wastewater utilities (16.6% in 2010), and 20.5% of its revenues from natural gas distribution utilities (nil in 2011).

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 four 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 (“DEP”) 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 DEP 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 DEP 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, the 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.

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

The APUC Businesses encompass operations which require adherence to environmental standards imposed by regulatory bodies through licences, permits, standards, policies and legislation. Failure to operate the APUC Businesses in strict compliance with these regulatory standards may expose the APUC Businesses 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, 2012. However it is expected that certain regimes will impact APUC, in terms of increased expenditures, and that these will 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 the 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 generally accepted industry practices. APCo's field personnel perform inspections of oil and chemical storage areas on a minimum of a quarterly basis. Liberty Utilities continuously monitor site remediation sites where the company has been named as a potential responsible party and maintain close communication 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 13 employees involved in the management of the corporation. APCo employs a total of 197 employees. With the exception of 39 employees at the EFW Facility and 6 employees at the Tinker Facility, the employees of APCo entities are non-unionized.

Liberty Utilities employs a total of 620 employees. Liberty Utilities employees are non-unionized with the exception of: 58 employees at the California Utility, 47 natural gas utility employees in the Liberty Utilities (Central) region, and 128 employees working for Liberty Utilities (East).

3.9 Foreign Operations

At the current exchange rate, approximately 59% of expected EBITDA in 2012 and 75% 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 APUC Businesses realize revenue 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 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

Liberty Utilities (West) region'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, Liberty Utilities (West) 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 Base Revenue Requirement Balancing Account ("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 \$35.5 million annually. This mechanism eliminates the risk of revenue variations associated with seasonal weather changes.

Liberty Utilities (East) in New Hampshire experiences peak loads in both the winter and summer seasons, due to heating and cooling loads associated with the 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.

Liberty Utilities (East) offers a comprehensive menu of energy efficiency programs in New Hampshire that, in turn, may reduce the demand for energy. Those 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. 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 customer. 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 crests in the winter months of January and February and declines in the summer months of July and August.

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, 2012, APUC Businesses' revenues were derived as follows: Manitoba Hydro – 7.1%; Hydro-Québec – 5.6%; PG&E – 3.4%; electricity sales and distribution – 29.3%; water distribution and wastewater treatment facilities – 2.6%; natural gas sales and distribution – 20.5%; waste disposal fees – 3.9%; and others – 11.7%.

3.12 Economic Dependence

The largest customer on a percentage basis is Manitoba Hydro which totalled 7.1% of gross revenues in the year ended December 31, 2012. This customer maintains an AA S&P rating and receivables are invoiced monthly and generally collected within 20 days.

Similarly, the second largest customer on a percentage basis is Hydro-Québec which totalled 5.6% of gross revenues in the year ended December 31, 2012. This customer maintains an A+ S&P rating and receivables are invoiced monthly and generally collected within 30 days.

Otherwise, APUC does not believe it is substantially dependant 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 licence 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

The APUC 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 plans on formally tracking 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 our engaged employees, creates an environmentally cleaner community, and enhances our partnership with all of our 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 addressing the environment include energy efficiency, water usage, habitat impact, greenhouse gas emissions monitoring, waste reduction and spill prevention. The Economic branch of our CSR efforts incorporates local spending, local hiring, and operational efficiency. Our 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 our investors, communities, environment, customers, employees, governments, and business partners

4. RISK FACTORS

The following are certain risk factors relating to the APUC 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 59% of EBITDA in 2012 and 75% 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 \$6.3 million (\$0.04 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 and may from time to time enter into derivative contracts to hedge the balance of the cash flow exposure. APUC's policy is not to utilize derivative financial instruments for trading or speculative purposes.

(b) **Market price risk**

APCo

The majority of APCo's electricity generating facilities sell their output pursuant to long-term PPAs. However, certain of APCo's hydroelectric facilities in the New England and New York regions sell energy at current spot market rates. In this regard, each \$10.00 per MW-hr change in the market prices in the New England and New York regions would result in a change in revenue of \$1.0 million on an annualized basis.

On May 15, 2012, APCo entered into a financial hedge, which expires December 31, 2016 with respect to its Dickson Dam hydroelectric 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 commences 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 commences 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 commences 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.

The January 1, 2013 acquisition of the Shady Oaks wind facility included a power sales contract which commences on January 1, 2013 for a 20 year period. The power sales contract is structured to provide pricing certainty for approximately 85% 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 \$0.5 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.

APCo

Approximately 82% of APCo renewable energy division's revenue, approximately 78% of APCo thermal energy division's revenue, and over 80% 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:

<u>Counterparty</u>	<u>Credit Rating *</u>	<u>Approximate Annual Revenues</u>	<u>Percent of Divisional Revenue</u>
Renewable Energy Division			
Manitoba Hydro	AA	26.2	28%
Hydro – Quebec	A+	20.8	23%
Ontario Electricity Financial Corporation	Aa2	10.0	11%
Maine Public Service**	BBB+	8.8	10%
ISO New England		3.8	4%
TransAlta Corp – Dickson Dam	BBB-	3.8	4%
Public Service Company of New Hampshire	BBB	1.4	2%
Total – Renewable		\$ 74.8	82%

Thermal Energy Division

Pacific Gas and Electric Company	BBB	12.4	39%
Connecticut Light and Power	A-	12.3	39%
Total – Thermal		\$ 24.7	78%
Total – APCo		\$ 99.5	80%

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* Ratings by Moody's or Standard & Poor's as of February 2013.

** Maine Public Service is a subsidiary of Emera.

APCo is also exposed to counterparty credit risk related to the financial hedges entered into with respect to certain facilities. These hedges have been entered predominately with large investment grade financial institutions pursuant to ISDA Master Agreements and Credit Support Annexes providing for security to be posted if certain exposure thresholds are met.

APCo continually monitors the credit rating of its major counterparties and the appropriateness of security if any that may be required.

Liberty Utilities

Liberty Utilities is exposed to credit risk with respect to amounts receivable from customers. Over 80% of Liberty's revenue is derived from services provided to residential customers and as a result there is minimal concentration risk to any one given counterparty. Liberty does not deem its counterparty and credit risk to be significant.

In addition to the counterparty risk related to customer sales outlined above, Liberty Utilities utilizes derivative instruments as hedges of certain price risks related to gas supply. As such Liberty is exposed to credit risk related to counterparties to the extent those derivative instruments are in an asset position at a point in time. Liberty manages the risk by entering into these instruments pursuant to ISDA agreements 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:

- APUC's operating credit facility is subject to a variable interest rate. The APUC Credit Facility has no amounts outstanding as at December 31, 2012. As a result, a 100 basis point change in the variable rate charged would not impact interest expense.
- The APCo Credit Facility had \$27.1 million outstanding as at December 31, 2012. As a result, a 100 basis point change in the variable rate charged would impact interest expense by \$0.3 million annually.
- APCo's project debt at its Sanger cogeneration facility has a balance of U.S. \$19.2 million as at December 31, 2012. 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 \$27.4 million outstanding as at December 31, 2012. As a result, a 100 basis point change in the variable rate charged would impact interest expense by \$0.3 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, 2012, APUC and its subsidiaries had a combined \$224.3 million of committed and available credit facilities remaining and \$53.1 million of cash resulting in \$277.4 million of total liquidity and capital reserves.

APUC currently pays a dividend of \$0.31 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 \$770.9 million with no significant maturities until 2015. 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**

APCo

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

- APCo's Sanger 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 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.

- APCo's BCI facility's energy services agreement 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 \$0.1 million.
- AES provides short-term energy requirements to various customers at fixed rates. The energy requirements of these customers are estimated at approximately 250,000 MW-hrs in fiscal 2013. While the Tinker facility is expected to provide a significant portion of the energy required to service these customers, AES anticipates having to purchase a portion of its energy requirements at the ISO-NE spot rates to supplement self-generated energy. In the event that AES was required to purchase all of its energy requirements at ISO-NE spot rates, each \$10.00 change per MW-hr in the market prices in ISO-NE would result in a change in expense of \$2.5 million on an annualized basis. This risk is mitigated through the use of short-term financial energy hedge contracts. AES has committed to acquire approximately 72,000 MW-hrs of net energy over the next 12 months at an average rate of approximately U.S. \$52 per MW-hr.

Liberty Utilities

Liberty Utilities (West)

Liberty Utilities is exposed to energy price risk in its Liberty Utilities (West) region which is mitigated through certain regulatory constructs. Liberty Utilities (West) provides electric service to the Lake Tahoe California basin and surrounding areas at rates approved by the CPUC. The utility 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 rate structure in California allows for a pass-through of energy costs to rate payers on a dollar for dollar basis, through the ECAC mechanism, which is designed to recoup power supply costs that are caused by the fluctuations in the price of fuel and purchased power. Actual power supply costs incurred by the facility are tracked and compared to the base rate power supply costs to ensure the cumulative variance, including carrying charges, does not exceed 5%. In the event that the cumulative variance exceeds 5%, the ECAC allows for an adjustment to the California Utility's approved rates (including carrying charges associated therewith), substantially eliminating the commodity risk associated with the purchase of power.

Liberty Utilities (Central)

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. Liberty Utilities (Central) 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 for its customers, Liberty Utilities (Central) has implemented a regulator sanctioned 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. Liberty Utilities (Central) 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.

Liberty Utilities (East)

In the Liberty Utilities (East) region, Granite State Electric Utility is an open access electric utility allowing for its customers to procure commodity services from competitive energy suppliers. For those customers that do not choose their own competitive energy supplier, Granite State Electric Utility provides a Default Service offering to each class of customers through a competitive bidding process. This process is undertaken semi-annually for residential and small use customers and quarterly for large customers. The winning bidder is obligated to provide a full requirements service based on the actual needs of Granite State Electric Utility'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 Granite State Electric Utility which in turn receives pass-through rate recovery through a formal filing and approval process with the NHPUC each quarter. Granite State Electric Utility 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, EnergyNorth Gas Utility purchases pipeline capacity, storage and commodity from a variety of counterparties. EnergyNorth Gas Utility's portfolio of assets, planning and forecasting methodology is approved by the NHPUC bi-annually through an Integrated Resource Plan filing. In addition, EnergyNorth Gas Utility 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. EnergyNorth Gas Utility 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, EnergyNorth Gas Utility 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, EnergyNorth Gas Utility 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.

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 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 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 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 \$7.1 million in its financial statements which was assumed in 2012 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 owner of the St. Leon Facility does not own the property on which its 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 cost to decommission the wind farm.

The owner of the Sandy Ridge, Senate and Minonk wind facilities 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 30-40 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 \$5.7 million as at December 31, 2012.

The owner of the EFW Facility owns the property on which its facility operates. The original Waste Supply Purchase Agreement for the EFW Facility ended in 2012. EFW Facility is currently operating with waste supplied from a number of municipal and commercial customers. As such the EFW Facility is much more reliant on revenue from electricity and steam sales. APCo is also attempting to negotiate a new Power Purchase Agreement with the Ontario Power Authority. While APCo will continue to source waste from the Ontario municipal and commercial sector the Ontario waste sector is extremely competitive. In the event that APCo is unable to successfully obtain waste at economic rates and/or successfully negotiate a PPA with the Ontario Power Authority, APCo may choose to close the facility but has no legal obligation to remove the assets. Should the EFW Facility ever be closed the cost of such closure has been assessed as immaterial.

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, 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, 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, expenses associated with replacing aging natural gas 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.

(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 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 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 facility inspections at minimum on an annual basis and 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 3-5 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 project, 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 facility inspections at minimum on an annual basis and 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 quality and 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 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 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 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 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 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.

Within Liberty Utilities East, one on-going environmental risk is currently being monitored.

The EnergyNorth Gas Utility and Granite State Electric Utility have been named as a potentially responsible party for remediation at 11 sites and 2 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 Utility 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 Utility 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 U.S. \$60.2 million, which at a discount rate of 3.5% represents U.S.\$56.6 million at December 31, 2012, 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 APCo operates facilities including Connecticut. RGGI drafted a 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 CO₂ emissions from large electrical generation facilities, including the Windsor Locks Facility. The RGGI regulation to implement a greenhouse gas cap and trade program was passed in Connecticut in late August 2008.

The Windsor Locks Facility is the only APCo 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, APCo only needs to purchase allowances for emissions from the 40 MW turbines which is expected to operate less than 100 hours per year and generate less than 3,000 tons of CO₂ per year. APCo has currently estimated the cost of compliance with the RGGI requirements for the Windsor Locks Facility to be between U.S. \$6 million and U.S. \$12 million.

RGGI has been in effect in Connecticut since 2009. The second compliance period is from January 2012 to December 2014. In 2012, the Facility produced 66,008 tons of CO₂, obtained allowances of 54,298 tons through the UTSA, and had 21,729 surplus tons rolled over from the first compliance period. As a result, no CO₂ allowances were required to be purchased to comply with RGGI. For 2013, it is estimated that the Facility will produce 3,000 tons of CO₂, with 10,019 banked allowances 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 the Regional Cap-and-Trade Program and taking the necessary steps to implement the Program within its jurisdiction. APCo owns and operates the Sanger 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 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 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. 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 the 2013 GHG emissions. Under this program, independent power generation facilities are not eligible for direct/free credits allocations, as such, the Sanger Facility will have to make provisions to purchase allowances. In 2012 Algonquin signed an amendment to the Power Purchase Agreement for the Sanger Facility that allows Algonquin 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 Facility’s costs of complying with California’s cap-and-trade regime for the period of 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 first year of implementation of the system will be a transition year. It will begin on January 1, 2012 and will allow emitters and participants to familiarize themselves with how the system works. Over the course of the year, emitters will also be able to make any adjustments that may be necessary to meet their obligations under the system for capping and reducing GHG emissions, which will come into force on January 1, 2013.

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.

APCo has submitted an annual greenhouse gas emissions inventory to the CDP since 2008. The inventory is presently being compiled for 2012. The emissions data includes both direct emissions from our 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 Litchfield Park Facility 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 Litchfield Park Facility 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 Litchfield Park Facility. 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 Litchfield Park Facility 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 LPSCOs 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 Litchfield Facility 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 Litchfield Park Facility’s customers.

In addition, the Litchfield Park Facility 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.

The Corporation'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, 2012.

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

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

(1) **Concord MGP**

EnergyNorth Gas Utility 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 NH, 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 Dept. of Transportation ("NHDOT") began site preparation work for the reconfiguration of that interchange. Subsequent investigations by EnergyNorth Gas Utility 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.

(2) **Dover MGP**

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

The evaluation of the nature and extent of MGP impacts to the site has been completed. Residual materials from the former MGP have been identified at the site and in the adjacent Cochecho 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, NH 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 Utility in April 2001. EnergyNorth Gas Utility 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.

(4) Laconia MGP & Liberty Hill Disposal Site

The former MGP was located in Laconia, NH. 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, NH.

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 its parent company, NU, and to EnergyNorth Gas Utility, another former owner. EnergyNorth Gas Utility 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 Utility retained responsibility for any decommissioning-related liabilities, including off-site disposal ("**Liberty Hill**").

Residual materials from the former MGP have been identified at the Laconia MGP site and in the adjacent Winnepesaukee 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 Utility has had no further involvement with the MGP site since the summer of 1999, except with regard to the Liberty Hill disposal area.

Liberty Hill Road site is currently under Phase III remediation. A Conceptual Remedial Design Report has been 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 Utility received a "Notification of Site Listing and Request for Site Investigation" for the former Manchester MGP located in NH from NHDES. Investigations conducted in the summer and fall 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 NH to the former plant owners/operators – EnergyNorth Gas Utility and PSNH and its parent company, 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.

(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 facility dams, and have put in place a plan to address deficiencies and are 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 impact the source of electricity for the California Utility. Any increases in cost of electricity will be passed on the ratepayers through the General Rate Case process.

(i) **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 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.

(g) 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.

APCo owns debt on seven hydroelectric facilities owned by Trafalgar. In 1997, an affiliate of APMI moved to foreclose on the assets, and subsequently Trafalgar went into bankruptcy. Trafalgar, APUC and an affiliate of APMI are involved in litigation over, among other things, a civil proceeding on the foreclosure on the assets and in bankruptcy proceedings.

With respect to the civil proceedings, the Second Circuit Court of Appeal dismissed all the claims against APCo 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 has filed a notice of appeal of the Memorandum-Decision and Order. Algonquin filed its brief on October 19, 2012 with a hearing dated anticipated in the first quarter of 2013. 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 Algonquin does not have a security interest in the monies transferred by Trafalgar before it filed for bankruptcy protection.

With respect to the bankruptcy proceedings, on January 30, 2013, the U.S. Second Circuit Court of Appeals held that APCo 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 U.S. Second Circuit Court of Appeals.

On October 21, 2011 the Québec Court of Appeal ordered a subsidiary of APUC to pay approximately \$5.4 million (including interest) to the government of Québec relating to water lease payments that the APUC subsidiary has been paying to the St. Lawrence Seaway Management Corporation ("**Seaway Management**") under its water lease with Seaway Management in prior years. The water lease with Seaway Management contains an indemnification clause which management 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 \$5.8 million. The parties are attempting to resolve this matter through good faith negotiations.

(h) 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 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.

(i) **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.

(j) **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 Businesses is in part dependant on regulatory climates in the jurisdictions in which it operates.

APCo

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. 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 hydro-electric generating facilities. Hydro 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 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 QF Status or 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, 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 Businesses in order to acquire funding for future growth acquisitions. Accordingly, dividends to shareholders are dependent upon the ability of each of the APUC 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 cannot be assured.

APCo

With the exception of the EFW Facility and the Tinker Facility, employees of APCo and their material subcontractors are non-unionized. The EFW Facility is unionized and a new collective bargaining agreement was renegotiated in 2011 for a term of three years, until April 2014. The Tinker Facility is unionized and a new collective bargaining agreement was renegotiated in January 2011 for a term of five years.

Liberty Utilities (West)

All employees of Liberty Utilities (West) are non-unionized with the exception of 49 employees at the California Utility. The California Utility is unionized and 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 Corporation has good relations with the IBEW union.

Liberty Utilities (Central)

All employees of Liberty Utilities’ water and wastewater utilities and their material subcontractors are non-unionized. There is one union contract with the IBEW covering 40 employees at the natural gas distribution utility in Missouri only. All the other 84 employees in Missouri, Iowa, and Illinois are non-union. The current 1 year contract was negotiated by Liberty and expires on June 1, 2013. Internal discussions have begun in preparation for negotiation meetings later with the union. Liberty Utilities has good relations with the IBEW union.

Liberty Utilities (East)

There are four union contracts in New Hampshire. The United Steelworkers represent approximately 88 employees working in field operations in gas. In the electric business there are two International Brotherhood of Electrical Workers locals representing approximately 25 field employees. There are also two engineers in the Utility Workers Union of America. The Steelworker contract was recently re-negotiated and will expire in April 2016. The IBEW contracts will expire in May 2014. The UWUA contract will expire on May 11, 2013 and are expected to be renegotiated without any issues.

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. Unitholders had previously been dependent on APMI for the administration of APCo and for management and operation of the Facilities. Since December 21, 2009, management of APUC has been conducted by officers of APUC. There may be situations in which conflicts of interest may arise between the Senior Executives of APUC in relation to the interests of APUC. Transactions involving related parties, including the Senior Executives who are principals of APMI, are disclosed in APUC’s annual financial statements and management’s discussion and analysis as at and for the period ended December 31, 2012.

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, 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 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 APUC common shares for fiscal 2010, 2011 and 2012 were \$22.8 million, \$32.4 million, and \$50.2 million, respectively. The amount of dividends declared for each Common Share of APUC for fiscal 2010, 2011 and 2012 were \$0.24, \$0.27 and \$0.30, respectively.

APUC follows a quarterly dividend schedule, subject to subsequent Board declarations each quarter. Effective August 9, 2012, the Board established a quarterly dividend of \$0.0775 or \$0.31 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 of directors, 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. An initial dividend of \$0.1603 per Series A Share was declared, and paid on December 31, 2012.

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 of APUC.

The purpose of the Reinvestment Plan is to enable Shareholders to invest all cash dividends on Common Shares in additional shares of APUC (“**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 APUC (“**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 TSX for the five (5) 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 26, 2013, 28.7 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 Shares 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, 2012, APUC had 188,763,486 issued and outstanding Common Shares and, as at March 26, 2013, APUC had 204,475,902 issued and outstanding Common Shares.

6.2 Private Placements of Subscription Receipts and Common Shares to Emera

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 Utility and EnergyNorth Gas Utility, 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 Utilities, 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 Utilities acquisition.

- On December 21, 2012, in connection with the acquisition of Emera's noncontrolling interest in Calpeco, 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.

Subsequent to the end of 2012, 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 (i) on February 7, 2013, 2,614,005 Common Shares upon the conversion of subscription receipts that were issued at a price of \$5.74 per subscription receipt and (ii) 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 March 26, 2013, in connection with the acquisition of the Georgia Utility, APUC issued 3,960,000 Common Shares at a price of \$7.40 per share to Emera for total proceeds of approximately \$29 million.

As at March 26, 2013, in total Emera now owns 50,126,766 Common Shares, representing approximately 24.51% 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 Gamesa Wind Facilities interests which closed on December 10, 2012.

As at December 31, 2012, APUC had 4.8 million Series A Shares outstanding.

Effective 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 "*General Development of the Business – Recent Developments – 2013 – Corporate – Agreement with St. Leon Class B unit holders*".

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 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 Common Shares on the Series 1A Redemption Date.

As a result of the redemption 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 APUC shares to the remaining holders of Series 2A Debentures, representing the number of freely tradable APUC shares obtained by dividing the aggregate principal amount of Debentures of \$57,041,000, by 95% of the current market price of 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 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 \$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 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 of APUC. 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 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, 2012, a total of 61,403 shares had been issued under the ESPP. For the year ended December 31, 2012, APUC issued 54,225 shares under the ESPP and recorded \$42 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 APUC common share. Dividends accumulate in the DSU account and are converted to DSUs based on the market value of the shares on that date. DSUs cannot be redeemed until the Director retires, resigns, or otherwise leaves the Board. The DSUs provide for settlement in cash or shares at the election of APUC. As APUC does not expect to settle the DSU’s in cash, these DSUs are accounted for as equity awards.

As at December 31, 2012, a total of 50,170 DSUs had been issued under the Deferred Share Unit Plan.

6.7 Performance Share Units

As at December 31, 2012, APUC had issued 21,123 performance share units (“PSUs”) 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 144% 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 ratably 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 of directors of the Corporation and shareholders with adequate time to evaluate any unsolicited take-over bid and, if appropriate, to seek out alternatives to maximize shareholder value. The Rights Plan was approved by

shareholders at the Meeting until the termination of the annual general meeting of the shareholders of APUC in 2013 or its termination under the terms of the Rights Plan. The Rights Plan is similar to rights plans adopted by many other Canadian corporations. 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 Shares by Emera under Allowed Transactions was waived following shareholder approval at the Annual and Special Meeting of Shareholders 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.

APUC has asked shareholders to approve an amendment and the continuance of the Rights Plan at the annual shareholders' meeting scheduled for April 23, 2013.

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;

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- 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 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 (5) 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 Share subdivision or consolidation, the number of Common Shares reserved for Option 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 30, 2012 the number of outstanding options is 3,681,710, which is 2.5% of the total outstanding Common Shares of the Corporation. The number of Common Shares that have been issued pursuant to the plan is nil.