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

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

For the fiscal year ended December 31, 2011 **Commission File Number** 000-53808

ALGONQUIN POWER & UTILITIES CORP.

(Exact name of Registrant as specified in its charter)

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

Canada
(Province or other jurisdiction of incorporation or organization)

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

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

2845 Bristol Circle
Oakville, Ontario
L6H 7H7, Canada
(905) 465-4500
(Address and telephone number of Registrant's principal executive offices)

C T Corporation System
111 Eighth Avenue
New York, New York 10011
(212) 894-8940
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

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

Title of each class	Name of each exchange on which registered
N/A	N/A

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

Common Shares, no par value
(Title of Class)

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act.

N/A
(Title of Class)

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

x **Annual Information Form** x **Audited Annual Financial Statements**

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

As of December 31, 2011, there were 136,122,780 Common Shares outstanding.

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

Yes x **No** ¨

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data

File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this Chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files)

Yes x **No** ¨

ANNUAL INFORMATION FORM

The Annual Information Form of Algonquin Power & Utilities Corp. ("Algonquin") for the fiscal year ended December 31, 2011 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, 2011 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, 2011 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 48) in the Management's Discussion and Analysis for the fiscal year ended December 31, 2011, 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, 2011, 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 of December 31, 2011.

KPMG LLP, the independent registered public accounting firm of Algonquin, which audited the consolidated financial statements of Algonquin for the year ended December 31, 2011, has also issued an attestation report on the effectiveness of Algonquin's internal control over financial reporting as of December 31, 2011.

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, 2011, is provided herein as Exhibit 99.4 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 48) in the Management's Discussion and Analysis for the fiscal year ended December 31, 2011, 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: apif@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 99) in the Annual Information Form for the fiscal year ended December 31, 2011, 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, 2011 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 35) in the Management’s Discussion and Analysis for the fiscal year ended December 31, 2011, 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 98) 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, 2011, filed as Exhibit 99.1 to this annual report on Form 40-F, is incorporated by reference herein.

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, 2011, 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, 2011,

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, 2011 is submitted as Exhibit 101 to this annual report on Form 40-F.

UNDERTAKING

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

CONSENT TO SERVICE OF PROCESS

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

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

SIGNATURES

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

ALGONQUIN POWER & UTILITIES CORP.
(Registrant)

Date: March 30, 2012

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

EXHIBIT INDEX

Exhibit	Description
99.1	Annual Information Form for the year ended December 31, 2011
99.2	Audited Annual Financial Statements for the year ended December 31, 2011
99.3	Management's Discussion & Analysis for the year ended December 31, 2011
99.4	Reports of KPMG LLP, Chartered Accountants, on Financial Statements and Internal Control Over Financial Reporting
99.5	Consent Letter from KPMG LLP, Chartered Accountants
99.6	Certifications of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
99.7	Certifications of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
99.8	Certifications of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.9	Certifications of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101	Interactive Data File

Exhibit 99.1



ALGONQUIN POWER & UTILITIES CORP.

ANNUAL INFORMATION FORM

March 30, 2012

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All information contained in this Annual Information Form ("AIF") is presented as at March 30, 2012, unless otherwise specified. In this AIF, all dollar figures are in Canadian dollars, unless otherwise indicated.

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 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 two separately managed regions – Liberty Utilities (South) and Liberty Utilities (West).

Unless the context indicates otherwise, references in this AIF to " **APUC**" include, for reporting purposes only, the direct or indirect subsidiaries of APUC and partnership interests held by APUC and its subsidiaries. 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.

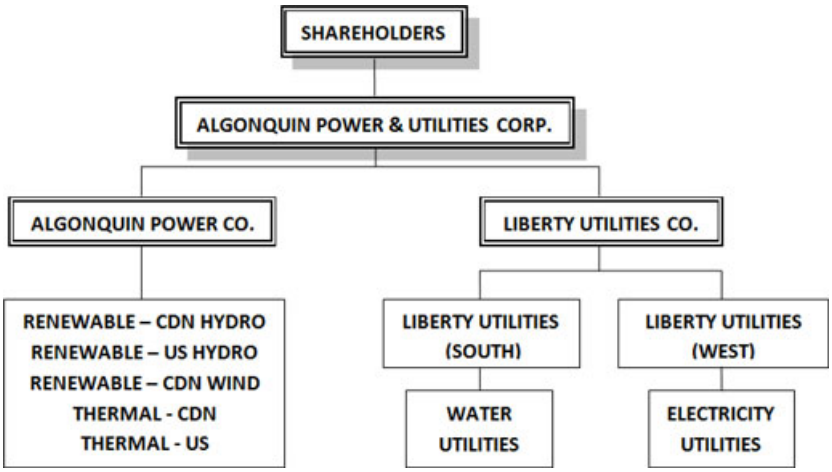
1.2 Intercorporate Relationships

(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., which in turn owns all of the issued and outstanding common shares of Liberty Utilities, a Delaware corporation, which in turn owns and operates the entities within the Liberty Utilities (South) and Liberty Utilities (West) regions. Each of APCo, the Liberty Utilities (South) region and the Liberty Utilities (West) region 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**"), APFC's subsidiaries include the ownership chain of and Algonquin Power Fund (America) Inc. ("**APFA**"). The Liberty Utilities (West) region is currently structured to hold the electric utility assets located in California and acquired January 1, 2011, and the Liberty Utilities (South) region is structured to hold the water distribution and wastewater treatment assets located in the United States.

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 and D.

(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 52.5% 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 holds 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 and the Côte Ste.-Catherine Facilities. 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. Ulric 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 ("**Fleur de Lis LP**"). Fleur de Lis 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 Fleur de Lis LP, the general partner owns a .02% equity interest, and a non-Algonquin, Saint-Damase party owns the remaining 49.995% equity interest. APT also has an interest in Société 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 24.9975% 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**"). It is owned by the 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 47.5% interest in APFC. St. Leon LP has issued 100 Class B limited partnership units. Two executives of APUC, Ian Robertson and Christopher Jarratt (the "**Senior Executives**") indirectly each own 18 of the 100 Class B units. 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.

APOT is the sole limited partner 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. which is also owned by APOT. 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 of Loyalist Wind Project LP ("**Loyalist LP**"), an Ontario limited partnership. APUC is the majority limited partner of Loyalist LP, holding a 87.49125% interest. The remaining limited partner of Loyalist LP is an unrelated third party, holding a 12.49875% 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 was incorporated in Nova Scotia and it controls the entities that own the majority of the 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. Brigette 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 100% owns Algonquin Power Services Canada Inc., a Canadian corporation that provides purchasing services to Canadian APCo entities.

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

APFA Group

APFA, a Delaware corporation, is owned by APA. APFA owns and controls the U.S. hydroelectric entities, and also controls the entities that own the U.S. thermal cogeneration facilities.

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 New York general partnerships Burt Dam Power Company and Hollow Dam Power Company own the Burt Dam and Hollow Dam Facilities, respectively. 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 Hydroelectric 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. The Otter Creek and Kings Falls Facilities are owned by Tug Hill Energy, Inc. a New York corporation, which is owned by Court Street Investments, Inc. ("**Court Street**"), a Massachusetts corporation, which in turn is owned 100% by APFA. Court Street also 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.

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.

In addition, APFA owns 100% of Algonquin Power Acquisition Inc., a Delaware corporation that was incorporated as an acquisition vehicle for proposed acquisitions by APCo in the United States. It currently has no assets. APFC also 100% owns Algonquin Power Services America LLC, a Delaware corporation that provides purchasing services to U.S. APCo entities.

(ii) Utilities Business

Liberty Utilities (South) Region

Liberty Water Co. ("**Liberty Water**"), a Delaware company, is the parent company of the entities within the Liberty Utilities (South) region. On December 22, 2010, APCo completed a corporate reorganization involving Liberty Water wherein 100% of the issued and outstanding common shares of Liberty Water Co. were transferred from APCo to Liberty Utilities.

Liberty Water indirectly owns the water and wastewater businesses located in Arizona, Texas, Missouri and Illinois, 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 Water**"; 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; and Algonquin Water Resources of Texas, LLC, a Texas limited liability company, owns water and water treatment assets at the resorts of Seaside, Holly Lake Ranch, Hill County, Piney Shores and The Villages (also known as "Big Eddy"). In Missouri, Algonquin Water Resources of Missouri, LLC, a Missouri limited liability company, owns assets associated with the Holiday Hills, Ozark Mountain, Timber Creek 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. All water and wastewater utilities are operated under the Liberty Water brand.

In addition, Algonquin Water Services LLC (" **Water Services**") is a company established to manage and operate water distribution and wastewater treatment facilities in Arizona and Texas. It is an Arizona limited liability company owned 99% by New Spring Acquisition Partnership, an Ontario partnership, which in turn is owned 50% by APCo. Algonquin Environmental Services LLC, a Delaware limited liability company owned 100% by Liberty Water, was also established to service various entities.

Liberty Utilities (West) Region

Liberty Energy Utilities Co. (“**Liberty Energy**”) is owned by Liberty Utilities and forms the top of the Liberty Utilities (West) region. Liberty Energy is a Delaware corporation. It owns 50.001% of 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.

Liberty Utilities (East) Region

Liberty Energy also owns Liberty Energy Utilities (New Hampshire) Corp. (“ **Liberty Energy (NH)**”), a Delaware corporation registered in New Hampshire. Liberty Energy Utilities (NH) is the named purchaser of the shares of Granite State Electric Company (“**Granite State**”) and EnergyNorth Natural Gas Inc. (“**EnergyNorth**”) currently owned by of National Grid USA (“ **National Grid**”).

Liberty Utilities (Central) Region

Liberty Energy also owns Liberty Energy (Midstates) Corp. (“ **Liberty Midstates**”), a Missouri corporation. Liberty Midstates is the named purchaser of certain natural gas distribution utility assets in Missouri, Iowa and Illinois (the “**Midwest Gas Utilities**”) currently owned by ATMOS Energy Corporation (“**Atmos**”).

(iii) Other

Outside of the APCo, Liberty Utilities (South) and Liberty Utilities (West) 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 to be used in future 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 Commandité ("**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, APUC 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. The LSR Subordinate Note was acquired by APCo on April 17, 1998.

2. GENERAL DEVELOPMENT OF THE BUSINESS

2.1 General

(a) The Unit Exchange

On October 27, 2009, APCo (formerly, Algonquin Power Income Fund) completed 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 (formerly Hydrogenics 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. Through subsequent internal reorganizations Algonquin Power Income Fund has since changed its name to Algonquin Power Co. and remains a subsidiary of APUC.

(b) Business Strategy

APUC is incorporated under the *Canada Business Corporations Act*. 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 $0.07 per share or $0.28 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 operations primarily through two businesses: independent power generation and utilities (water, gas and electric). These businesses of APUC are herein referred to as the "**APUC Businesses**".

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 the 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 operating in Ontario, Québec, Newfoundland, New Brunswick, Alberta, New York State, New Hampshire, Vermont, Maine and New Jersey with a combined generating capacity of approximately 165 MW.

APCo also owns wind powered generating stations in Manitoba with a combined generation capacity of 120 MW and holds debt securities in a 26 MW wind powered generating station in Saskatchewan.

All of the wind energy facilities' electrical output is sold pursuant to long term power purchase agreements ("**PPAs**") with major utilities which have a weighted average remaining contract life of 20 years. Approximately 80% of the electrical output from the hydroelectric facilities is sold pursuant to long term PPAs with major utilities which have a weighted average remaining contract life of 8.5 years.

APCo owns thermal energy facilities including an energy-from-waste facility in Ontario, diesel generating facilities in Maine and New Brunswick and natural gas-fired cogeneration facilities in each of California, Connecticut, and Ontario. APCo also holds ownership interests in three facilities in Ontario and Quebec. Approximately 67% of the electrical output from the owned thermal facilities is sold pursuant to long term PPAs with major utilities and which have a weighted average remaining contract life of 11 years. Detailed information on the facilities owned and operated by APCo is set out in Schedules A and B.

Utilities: Liberty Utilities owns and operates utilities through two regions, Liberty Utilities (West) and Liberty Utilities (South). Liberty Utilities (West) is in the electricity distribution, transmission and generation sector. Liberty Utilities (South) is in the water distribution and wastewater treatment sector. The underlying business strategy is to be a leading provider of safe, high quality and reliable utility services while providing stable and predictable earnings from utility

operations. In addition to encouraging and supporting organic growth within its service territories, Liberty Utilities is focused on delivering continued growth in earnings by identifying acquisition opportunities which provides accretive expansion of its business portfolio.

Liberty Utilities (South) provides water and wastewater utility services to approximately 76,000 customers through 21 water distribution and wastewater collection and treatment utility systems located in Arizona, Illinois, Missouri and Texas. These utilities generally operate under rate regulation, overseen by the public utility commissions of the States in which they operate. Detailed information on the water distribution and wastewater utility systems owned and operated by Liberty Utilities is set out in Schedule C.

Liberty Utilities (West) provides local electrical utility services to approximately 47,000 customers in the Lake Tahoe region of California. Detailed information on the electrical utilities system owned and operated by Liberty Utilities (West) is set out in Schedule D.

As the currently committed growth initiatives are completed, additional management regions will be created. The Liberty Utilities (East) region will be formed to deliver electrical and natural gas distribution services upon completion of the acquisitions of Granite State and EnergyNorth. The Liberty Utilities (Central) region will be formed to manage natural gas distribution services upon completion of the Midwest Gas Utilities acquisition.

2.2 Three Year History

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

(a) Fiscal 2009

Corporate

i) **Conversion to a Corporation**

On October 27, 2009, APCo and the Corporation completed the Unit Exchange. See " *General Development of the Business – General – The Unit Exchange*". As part of the Unit Exchange, on October 27, 2009, the trustees of APCo became the directors of APUC.

Also on October 27, 2009, in connection with the Unit Exchange, the debentureholders of APCo exchanged their convertible debentures for convertible debentures of the Corporation or Common Shares. As a result, the debentureholders of APCo became debentureholders and shareholders of the Corporation. See "*Description of Capital Structure – Convertible Debentures*".

ii) **Equity and Convertible Debenture Offering**

On December 2, 2009, APUC completed a public offering of (i) 5,980,000 Common Shares at a price of $3.35 per Common Share for gross proceeds of approximately $20 million and (ii) approximately $55 million principal amount of 7% convertible unsecured subordinated debentures due June 30, 2017 (the "**Series 3 Debentures**" or the "**APUC Debentures**"). The underwriters of the offering also exercised in full an over-allotment option to purchase an additional 897,000 Common Shares and approximately $8.2 million principal amount of Series 3 Debentures resulting in aggregate gross proceeds of approximately $86.2 million. See "*Description of Capital Structure—Convertible Debentures*".

iii) **Internalization of Management**

On December 21, 2009, the Board reached agreement with the shareholders of Algonquin Power Management Inc. (" **APMI**") to internalize all management functions of APCo which were previously provided by APMI. APMI was the manager of APCo and APUC up to December 22, 2009 and two executives of APUC, the Senior Executives, are principals of APMI. APUC acquired the interest previously held by APMI in the management services agreement, with consideration paid in the form of issuance of 1,158,748 Common Shares of APUC.

(b) 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) **AES**

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**

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 April 23, 2009, APUC announced plans to co-acquire an electrical generation and regulated distribution utility (the " **California Utility**") in partnership with Emera, pursuant to the asset purchase agreement by and between Sierra Pacific Power Company d/b/a NV Energy and Calpeco dated April 22, 2009 (the "**Purchase Agreement**").

On January 1, 2011, APUC, in partnership with Emera, completed the transaction and acquired the assets comprising the California Utility for a gross purchase price of U.S. $136.1 million, subject to certain working capital and other closing adjustments. Liberty Utilities owns 50.001% and Emera owns 49.999% of California Pacific Utility Ventures LLC, which owns 100% of the purchaser of the California Utility assets, Calpeco.

For a more detailed discussion of this acquisition, see " *General Development of the Business—Significant Acquisitions – 2011 – Liberty Utilities – California Utility Acquisition*".

(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, a regulated electric distribution utility, and EnergyNorth, 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 (the "**Purchase Agreements**").

For a more detailed discussion of this acquisition, see " *General Development of the Business—Significant Acquisitions – 2011: New Hampshire Utility Acquisition*".

(iii) **Liberty Utilities (South) – Rate Cases**

Liberty Utilities (South) had ongoing rate cases at a number of its utilities which were processed throughout 2010. See " *Description of the business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Utilities: Water and Wastewater – Rate Cases—General*" for further discussion of the status of these rate cases. During the year ended December 31, 2010, Liberty Utilities (South) 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 in the Liberty Utilities (South) region. 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) **Liberty Utilities (West) – 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.

(v) **Liberty Utilities (South) – Senior Debt Financing**

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 bear interest until June 2016 when annual principal repayments of U.S. $5.0 million annually commence. The funds were used to reduce outstanding indebtedness under APCo's senior credit facility.

(c) Fiscal 2011

Corporate

(i) **Strengthened Liquidity—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 will be used to fund a portion of the investment related to previously announced growth initiatives for both Liberty Utilities and APCo, to partially repay existing indebtedness and for other general corporate purposes.

(ii) **Strengthened Balance Sheet—Conversion of Convertible Debentures to Equity**

Effective May 16, 2011 ("**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 Redemption Date, $60.339 million principal amount of Series 1A Debentures were converted by debentureholders 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 Agreement**") with Emera which establishes how APUC and Emera will work together to pursue specific strategic investments of mutual benefit. The Strategic Agreement builds on the strategic partnership effectively established between the two companies in April 2009.

The Strategic 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 projects within its service territories and large electric utilities. These "areas of pursuit" are intended to represent investment areas in which there is potential overlap between Algonquin and Emera and are not exhaustive of either company's business focus and do not limit in any way the activities which either APUC or Emera can undertake. Each of APUC or Emera are free to undertake independently investments within their own "area of pursuit" and outside the other party's "areas of pursuit". Under the Strategic Agreement, to the extent either APUC or Emera encounter opportunities which fall within the other's "areas of pursuit", they are committed to work with the other party in the development of such investment opportunities.

As an element of the Strategic Agreement, Emera's allowed common equity interest in APUC will be increased from 15% to 25%. The Strategic Agreement was approved by shareholders at the annual and special general meeting held on June 21, 2011.

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 is in the process of acquiring a new combustion gas turbine which is more appropriately sized to meet the electrical and steam requirements of the steam host. The new cogeneration equipment is in construction with commercial operation expected in July 2012. The total expected capital cost for this project is estimated at approximately U.S. $25 million. APCo believes it is eligible to receive a one-time non-recurring grant from the State of Connecticut equivalent to U.S. $450/KW to a maximum of U.S. $6.6 million which would offset the cost of such re-powering. APCo also believes that this project would qualify for a combined heat and power investment tax credit ("**ITC**") sponsored by the U.S. Federal Government. The benefit of the ITC grant is approximately U.S. $1 million in addition to the Connecticut DPUC grant would offset the cost of such re-powering.

For a more detailed discussion of this, see " *Description of the business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Thermal— Cogeneration – Material Facilities – Windsor Locks Facility*".

(iii) **APCo Senior Unsecured Debentures**

On July 25, 2011, APCo issued $135 million in senior unsecured debentures (the " **Senior Unsecured Debentures**") by way of private placement. The net proceeds from the Senior Unsecured 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 Senior Unsecured 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 Facility Renewal**

On January 14, 2011, APCo received commitments from a syndicate of Canadian banks for a new $142 million credit facility with a three year term (the "**APCo Facility**"). The APCo Facility matures on February 14, 2014. APCo reduced the amount of the APCo Facility to $120 million following the completion of the Senior Unsecured Debenture private placement by APCo in July 2011.

As at March 30, 2012, APCo had used the APCo Facility to post (i) a letter of credit in the approximate amount of U.S. $19.5 million in respect of the Sanger Facility; (ii) a $1.0 million letter of credit in respect of the Dickson Dam Facility; (iii) letters of credit for the EFW Facility totalling $5.4 million; (iv) letters of credit pursuant to the BCI Facility totalling $2.4 million; (v) letters of credit in connection with the St. Leon Facility totalling $1.8 million; (vi) letters of credit in connection with the Long Sault Rapids Facility totalling $1.2 million; (vii) letters of credit in connection with the St. Leon II Wind Project totalling $3.4 million; (viii) letters of credit in connection with the Cornwall Solar Project totalling $0.5 million; (ix) letters of credit in connection with the various wind development projects totalling $6.9 million; and (viii) various other letters of credit required by APCo entities totalling $0.3 million.

Liberty Utilities

(i) **California Utility**

On April 29, 2011, pursuant to the Strategic 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 (the "**Subscription Agreement (Calpeco)"**), 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 proceeds of this subscription receipt transaction will be used to fund the acquisition by Liberty Utilities of Emera US Holdings Inc.'s interest in the California Utility. 4,790,000 subscription receipts will convert into APUC shares on a one-for-one basis following regulatory approval of the transfer of 100% of the California Utility to Liberty Utilities (expected in early 2012), at which time the $22,608,800 promissory note delivered by Emera to APUC to satisfy the subscription price of the first tranche of subscription receipts become due and payable. The remaining 3,421,000 subscription receipts will convert into APUC shares on a one-for-one basis following completion of the California Utility's first rate case, expected to be completed in early 2013, at which time the $16,147,120 promissory note delivered by Emera to APUC to satisfy the subscription price of the second tranche of subscription receipts become due and payable. In the event of termination of the Subscription Agreement (Calpeco), the promissory notes will be returned to Emera for cancellation, the subscription receipts will be returned to APUC for cancellation, and the parties will have no further obligations under the Subscription Agreement (Calpeco).

2.3 Recent Developments—2012

Corporate

(i) **Strengthened Balance Sheet—Conversion of Convertible Debentures to Equity**

Effective February 24, 2012 ("**Series 2A Redemption Date**"), APUC redeemed $57.0 million, representing the remaining issued and outstanding principal amount, of 6.35% convertible unsecured subordinated debentures due November 30, 2016 (the "**Series 2A Debentures**") at a price of $1,000 per debenture by issuing and delivering an aggregate of 9,836,520 APUC shares. Between January 1, 2012 and the Series 2A Redemption Date, $2.9 million principal amount of Series 2A Debentures were converted by debentureholders into 485,998 shares of APUC.

(ii) **Business Associations with APMI and Senior Executives.**

There have been a number of business relationships between the Senior Executives (being Ian Robertson and Chris Jarratt), APMI 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 conducted 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, 2011 are listed below. Subsequent to December 31, 2011, APUC and the Parties reached an agreement to resolve a number of the business associations and relationships (the "**Agreement**"). 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 and 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.

St. Leon wind power generating facility

St. Leon is a 104 MW wind power generating facility which has issued Class B units to external parties and Senior Executives. APUC and the Class B unit holders have simplified the relationship by amalgamating the previous partnership agreement and two amending agreements into an amended and restated agreement. In addition, APUC and the Class B holders have executed an agreement which outlines the relationship of the parties in relation to the St. Leon II expansion of the St Leon facility ("Expansion Agreement"). The terms of the Expansion Agreement allow APUC to expand the St Leon project on a "no-net-harm-basis" to the Class B holders and provide APUC with the full economic benefit of such expansion.

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 $100 in relation to the development of this project. In 2008, APUC accrued $100 as an estimate of the final fee owed to APMI. This relationship and corresponding liability 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. APUC entered into an agreement and remitted $1.3 million to the affiliate as an advance against expense reimbursements. At December 31, 2011, $279 of the advance remained. The Board has undertaken an independent review of the relationship and believes that continuing the original arrangement is beneficial to the company. The current arrangement is expected to end in approximately 2016 when the advance will be fully utilized.

Office lease

APUC has leased its head office facilities on a triple net basis from an entity partially owned by Senior Executives. The original lease was due to expire in December 31, 2012. Effective April 1, 2011, a subsidiary of APUC leased its head office facilities from a third party in a new stand alone building immediately adjacent to APUC's head office for a term of 5 years ending December 31, 2015 with an additional 5 year renewal option. APUC has amended its lease at

its existing premises to be co-terminus with its subsidiary's new lease. The majority of terms in the amended lease are identical. Based on a review of the real estate leasing market in the fall of 2010, APUC believes the amended lease is on terms equivalent to fair market value for prime office space of similar size and quality.

Operations services

Staff managed by APUC have historically operated an additional three hydroelectric generating facilities where Senior Executives hold an interest. Effective January 1, 2011, management of these facilities is now being undertaken by an affiliate of APMI. APUC and the APMI affiliate had agreed to provide some transition services to each other until December 31, 2011. Costs for providing such transition services are intended to be on a cost recovery basis with no mark-up for profit. APUC agreed to provide supervisory management on a cost recovery basis for one of the facilities until December 31, 2012 to provide sufficient time for APMI to make alternative arrangements to manage the facility.

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. In 2008, APUC accrued U.S. $0.6 million as an estimate of the final fee owed to APMI. This liability was settled pursuant to the Agreement.

Clean Power Income Fund

During 2007, Algonquin allowed its offer to acquire Clean Power Income Fund 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 liability 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. APUC has acquired APMI's interest in these royalties for an amount of $0.6 million. APMI is also entitled to a development fee of up to $0.4 million following commercial operation of the project and has agreed to permit the Board to determine whether it will retain this fee following commercial operation of the facility. This liability 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. The Second Circuit Court of Appeals dismissed all the claims against APCo in the civil proceedings and remanded one issue to the District Court. The bankruptcy proceedings are continuing.

Settlement of Other Business Associations.

Subsequent to December 31, 2011, APUC and the Parties reached an Agreement to resolve a number of the historic joint business associations between APUC and the Parties. The transaction is subject to finalization of definitive agreements which are expected to be completed in the second quarter of 2012.

Under this term sheet, it is proposed that 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 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.

APCo—Power Generation

(i) **Acquisition of U.S. Wind Farms**

On March 9, 2012, APCo entered into an agreement to acquire a 51% majority interest in a 480 MW portfolio of four wind power projects in the United States (the "**Projects**") from Gamesa Corporación Tecnológica, S.A. (" **Gamesa**") for total consideration of approximately U.S. $888 million.

APCo will contribute U.S. $269 million to partially fund the acquisition of the Projects; tax assisted equity investors will contribute U.S. $360 million. APCo intends to finance its investment with approximately 45% debt and 55% equity. The portfolio will be acquired in two stages; closing of two existing wind farms is expected to occur promptly following receipt of regulatory approval and the acquisition of the remaining two wind farms following their respective commissioning near the end of 2012.

The Projects consist of four facilities, Minonk (200MW), Senate (150MW), Pocahontas Prairie (80MW) and Sandy Ridge (50MW) located in the states of Illinois, Texas, Iowa and Pennsylvania, respectively. Pocahontas Prairie and Sandy Ridge have recently reached their commercial operation dates ("**COD**") in February 2012, and Senate and Minonk are in construction with COD anticipated in Q4 2012. Total annual energy production from the four facilities is expected to be 1,644 GW-hrs per year. The Projects are comprised of 240 Gamesa

G9X-2.0 MW wind turbines. The Projects each have entered into a 20 year contract with Gamesa to provide operations, warranty and maintenance services for the wind turbines and balance of plant facilities.

The Projects have long term, fixed price power sales contracts (the " **Power Sales Contracts**") with a weighted average life of 11.8 years (Minonk and Sandy Ridge 10 years, Senate 15 years). Approximately 73% of energy revenues would be earned under the Power Sales Contracts. All energy produced in excess of that sold under the Power Sales Contracts, together with ancillary services including capacity and renewable energy credits, will be sold into the energy markets in which the facilities are located.

(ii) **St. Leon Facility Expansion**

On July 18, 2011, APCo entered into a 25-year PPA with Manitoba Hydro in respect of the St. Leon II Facility located in the Province of Manitoba.

Construction of this project commenced on August 30, 2011. The final turbine was erected in February 2012 and the project is generating energy on all units as of March 1, 2012. The total capital cost of the project is expected to be $29.5 million. The project is expected to achieve commercial operation early in the second quarter of 2012 with revenues in the first full year of operating following commissioning expected to be $3.8 million.

(iii) **New Projects under Development**

As of March 7, 2012, APCo had been awarded or acquired interests in 7 major power development projects that significantly expands the company's electrical generation capacity by 350 MW and once completed will increase the company's annual generation production by over 1,200 GWhrs. Each project has a PPA with a Canadian provincial utility and has a contract length of 20 years or longer.

The following summarizes a number of projects under development and for which PPA's have been awarded since December 2010.

Project Name (Location)	Location	Size (MW)	Estimated Capital Cost	Commercial Operation	PPA Term	Production GWhr
Chaplin Wind	Saskatchewan	177	$355.0	2016	25	720.0
Amherst Island	Ontario	75	$230.0	2014	25	247.0
Morse Wind [1]	Saskatchewan	25	$70.0	2014	20	93.0
St. Damase	Quebec	24	$70.0	2013	20	86.0
Val Eo	Quebec	24	$70.0	2015	20	66.0
St. Leon II	Manitoba	17	$30.0	2012	25	58.0
Cornwall Solar	Ontario	10	$45.0	2013	20	13.4
Total		**352**	**$870.0**			**1,283.4**

[1] The Morse Wind Project is comprised of three contiguous projects with 25 MW in aggregate installed generating capacity. The two 10 MW PPA's were awarded in May 2010 and the 5 MW PPA was awarded in June 2011.

For a more detailed discussion of these projects, see " *Description of the business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Development – Current Development Projects*".

Liberty Utilities

i) ***New Hampshire Utility Acquisition update***

On December 9, 2010 Liberty Utilities entered into agreements to acquire all issued and outstanding shares of Granite State and EnergyNorth. For a more detailed discussion of this acquisition, see "*General Development of the Business – Significant Acquisitions – 2011 – New Hampshire Utility Acquisition"*.

The closing of the transaction is subject to approval by the New Hampshire Public Utilities Commission (" **NHPUC**"). Liberty Utilities is currently proceeding through the regulatory approval process. A series of technical sessions with the NHPUC have been held to review the merits of the transaction, identify key transitional issues and resolve issues raised by commission staff, the consumer advocate and other interveners. Liberty Utilities and National Grid are now working with the NHPUC Staff and Consumer Advocate to prepare a settlement recommendation to present to the Commissioners of the NHPUC for consideration and ultimate approval. The current regulatory hearing schedule should allow for a public hearing early in the second quarter of 2012, with a commission decision expected shortly thereafter. This would likely to result in closing occurring towards the end of the second quarter of 2012.

ii) ***Midwest Utility Acquisition update***

On May 13, 2011, Liberty Utilities entered into an agreement with Atmos to acquire their regulated natural gas distribution utility assets (the "**Midwest Gas Utilities**") located in Missouri, Iowa, and Illinois. Total purchase price for the Midwest Gas Utilities is approximately U.S. $124 million, subject to certain working capital and other closing adjustments. Liberty Utilities expects to acquire assets for rate making purposes of approximately U.S. $112 million. For a more detailed discussion of this acquisition, see "*General Development of the Business – Significant Acquisitions – 2011 – Midwest Gas Utilities Acquisition"*.

The closing of the transaction is subject to approval by the Missouri Public Service Commission (" **MPSC**"), Iowa Utilities Board ("**IUB**"), and Illinois Commerce Commission ("**ICC**"). Liberty Utilities has received approval from the IUB and has entered a unanimous stipulation with the MPSC. Liberty Utilities is currently proceeding through the regulatory approval process with the ICC which requires the Company, Atmos and the ICC staff to review the merits of the transaction. A hearing on a limited set of issues was held in Illinois in January 2012, and a proposed ICC decision is expected in the second quarter of 2012. Management expects closing to occur towards the end of the second quarter of 2012.

iii) ***Liberty Utilities Credit Facility***

On January 19, 2012, Liberty Utilities entered into an agreement for a U.S. $80 million senior unsecured revolving credit facility (the " **Liberty Facility**") with a three year term. Initially, U.S. $25 million will be available immediately to support the operations of Liberty Utilities and its current subsidiaries. The additional U.S. $55 million will be automatically available to Liberty Utilities to support operations and working capital requirements of all committed regulated utility acquisitions following the closing of the previously announced acquisition of Granite State and EnergyNorth. The Liberty Facility can be increased to accommodate future working capital needs or other requirements.

As at March 25, 2012, Liberty Utilities had used the Liberty Facility to post (i) four letters of credit in the approximate amount of U.S. $1.2 million in respect of Liberty Utilities (South).

2.4 Significant Acquisitions and Investments—2011

APCo—Power Generation

i) Cornwall Solar

APCo entered into a share purchase agreement with EffiSolar Energy Corporation (" **EffiSolar**") to acquire all of the issued and outstanding shares of Cornwall Solar Inc. based upon the achievement of specific milestones. On December 30, 2011 OPA approval was received and the transaction closed on January 4, 2012. Cornwall Solar owns the rights to develop a 10 MWac solar project located near Cornwall, Ontario. In addition to the Cornwall project, APCo has acquired an option to acquire 10 additional Ontario based solar projects. Projects in the Feed-in-Tariff ("**FIT**") pipeline have submitted FIT applications for an additional 100MWac.

For a more detailed discussion of this acquisition, see " *Description of the business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Development—Current Development Projects*".

ii) Red Lily Wind Project

On February 28, 2011 the 26.4 MW wind generation facility in southeastern Saskatchewan (" **Red Lily I**") commenced commercial operation under the PPA. APUC's investment in Red Lily I has been initially structured in the form of senior and subordinated debt investment of approximately $19.6 million with returns to APUC from the project coming in the form of interest payments and other fees in 2011.

Project construction costs at Red Lily I were approximately $71.2 million. APUC and APCo earned $1.6 million in interest income and $1.9 million in other payments and fees in 2011, representing approximately 75% of the expected net cash flows from Red Lily I. APUC has the option to formally exchange its debt investment and fee interest in the project for a 75% equity interest in Red Lily I, exercisable in February 2016.

Liberty Utilities

i) California Utility Acquisition

On January 1, 2011, APUC, in partnership with Emera, completed the transaction and acquired the assets comprising the California Utility for a gross purchase price of U.S. $136.1 million, subject to certain working capital and other closing adjustments.

On April 23, 2009, APUC agreed to co-acquire an electrical generation and regulated distribution utility in partnership with Emera. APUC and Emera would own 50.001% and 49.999%, respectively, of CPUV, which owns 100% of Calpeco. Calpeco was formed to acquire the California-based electricity distribution and related generation assets of NV Energy for the purchase price of approximately US $132 million, subject to certain working capital and other closing adjustments, as outlined in the Purchase Agreement.

In October 2009, an application was filed with the CPUC requesting approval of the transaction in which NV Energy had agreed to sell its California electric distribution and generation assets to Calpeco. The transaction was subject to State and Federal regulatory approval. On January 1, 2011, following receipt of all U.S. State and Federal regulatory approvals, Calpeco acquired the assets comprising the California Utility. The California Utility provides electric distribution service to approximately 47,000 customers in the Lake Tahoe region.

As an element of the California Utility partnership, pursuant to a subscription and unitholder agreement dated April 22, 2009 (the " **Subscription Agreement**"), Emera agreed to a conditional treasury subscription of approximately 8.5 million Trust Units of APCo at a price of $3.25 per unit. Subsequent to the completion of the Unit Exchange, the Subscription Agreement was amended to reflect a subscription of Common Shares rather than Trust Units of Algonquin. Upon closing, Emera exchanged these subscription receipts into 8.523 million Common Shares at a purchase price of $3.25 per Common Share. The proceeds of the subscription receipts were utilized to fund Liberty Utilities (West)'s ownership share of the cost of acquisition of the California Utility.

The acquisition was also 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 solely an obligation 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.

ii) **New Hampshire Utility Acquisition**

On December 9, 2010, APUC announced that Liberty Energy had entered into agreements to acquire all issued and outstanding shares of Granite State, a regulated electric distribution utility, and EnergyNorth, a regulated natural gas distribution utility from National Grid for total consideration of U.S. $285.0 million, subject to certain working capital and other closing adjustments, as outlined in the NH Purchase Agreements.

Granite State provides electric service to over 43,000 customers in 21 communities in New Hampshire. EnergyNorth provides natural gas services to over 83,000 customers in five counties and 30 communities in New Hampshire. Granite State and EnergyNorth are anticipated to have regulatory assets at closing of approximately U.S. $72.0 million and U.S. $178.8 million, respectively.

Closings of the transactions are subject to certain conditions including state and federal regulatory approval, and are expected to occur in 2012. Financing of the acquisitions is expected to occur simultaneously with the closing of the transactions. Liberty Energy is targeting a capital structure with not more than 50% debt to total capital, consistent with investment grade utilities.

As an element of the EnergyNorth and Granite State acquisitions and pursuant to a subscription agreement dated March 25, 2011 (the "**Subscription Agreement (National Grid)**"), Emera subscribed for 12,000,000 subscription receipts of APUC at a price of $5.00 per subscription receipts. Payment for the subscription receipts was satisfied by delivery by Emera of a non-interest bearing promissory note in the amount of $60,000,000. Upon satisfaction of the conditions precedent to the closing of the National Grid transactions (other than payment of the purchase price), including the receipt of all necessary regulatory approvals, the promissory note

will become due and payable and the rights evidenced by the subscription receipts will be deemed to have been satisfied by the delivery of Common Shares from APUC on a one-for-one basis, subject to customary anti-dilution adjustments. Delivery of Common Shares of APUC upon conversion of the subscription receipts is conditional on and is planned to occur simultaneously with the closing of the acquisition of Granite State and EnergyNorth. In the event of termination of the Subscription Agreement (National Grid), the promissory note will be returned to Emera for cancellation, the subscription receipts will be returned to APUC for cancellation, and the parties will have no further obligations under the Subscription Agreement (National Grid).

iii) **Midwest Gas Utility Acquisition**

On May 13, 2011, Liberty Utilities entered into an agreement with Atmos to acquire their regulated natural gas distribution utility assets (the "**Midwest Gas Utilities**") located in Missouri, Iowa, and Illinois. Total purchase price for the Midwest Gas Utilities is approximately U.S. $124 million, subject to certain working capital and other closing adjustments, as outlined in the share purchase agreements by and between Atmos and Liberty Midstates entered into on May 12, 2011 (the "**Midwest Purchase Agreements**").

Liberty Utilities expects to acquire assets for rate making purposes of approximately U.S. $112 million.

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.

In 2007, the Canadian Federal government established a new Renewable Power Production Incentive program (" **RPPI**") called "ecoEnergy for Renewable Power" that was created to stimulate up to 14.3 terawatt hours of other new renewable energy. The RPPI provides for an incentive of $10 per MW-Hr of production for the first ten years of operations for eligible projects commissioned after April 1, 2007 and before March 31, 2011. Eligible technologies include waterpower, advanced, innovative and highly efficient biomass, combustion technologies using

biogas and other renewable technologies. Although no new contribution agreements will be signed after March 31, 2011, signed agreements will continue to receive payments as outlined in contribution agreements 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

While Qualifying Facilities ("**QFs**"), which comprise the majority of APCo's US facilities, 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 4, 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 4, 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 Costs**" means costs a utility does not incur to add new generating capacity to the system by purchasing electricity from an independent or parallel generator.

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 nondiscriminatory 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 nondiscriminatory 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

(i) United States Water Services Industry

Investor-owned utilities are subject to 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 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 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 rate payers 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

(i) United States Electric Services Industry

Investor-owned electricity utilities are subject to 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%.

Generally, electricity providers in the United States operate as geographic monopolies within the areas in which they serve. An electricity 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 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.

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. This oversight also includes cost-of-service regulation to establish 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 in order to determine the revenue requirement upon which each utility's customer rates are set. 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.

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 headpond.

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, full 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 facilities in which APCo has an interest pursuant to, the existing contracts. APCo has 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 $1.5 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:

	Total	2012	2013	2014	2015
Estimated future Bill C-93 Capital Expenditures	**16,900**	1,100	5,300	7,700	2,800

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 anticipates completing the on-site remediation work in 2012.
- 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 anticipates completing the engineering in 2012 and performing the remedial work in 2013 and 2014.
- The dam safety study for the St. Alban facility was completed in 2010 followed by a detailed condition assessment in 2011. APCO will review the results of the condition assessment and finalize the remediation plan for this dam in 2012. APCo anticipates engineering and regulatory review to be performed in 2012 and 2013, with remedial work 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.
- The dam remediation work related to Chute Ford will be completed in 2012 while the work related to the St. Raphael and Riviere-du-Loup facilities is anticipated to be completed in 2013. No dam remediation work is required at the Arthurville, Hydraska, and Ste-Brigitte facilities.
- The dam remediation work related to the Rawdon facility was completed in 2011.

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 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 "*Hydroelectric – Long Sault Rapids Facility—Credit Agreements*" below).

APCo's interest in the Facility was acquired by way of subscribing to two notes from the original developers. The notes receivable have a face value of approximately $17 million and bear interest at 9%. 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 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.

i) PPA

Pursuant to the terms of the PPA, the Co-Owners sell power produced by the Facility exclusively to OEFC. The PPA terminates 50 years from the commercial in-service date, April 1, 1998, and may be renewed for a further term upon request by either party on terms and conditions to be mutually agreed. The rates are escalated annually based on an index figure tied to the greater of OEFC's Total Market Cost index (a minimum of 1% to a maximum of 8%).

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

ii) 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.

iii) Co-Owners Agreement and Management Agreement

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

iv) Credit Agreements

There is an outstanding senior loan against the Facility in the amount of $39.0 million at December 31, 2011. 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, 2011, the debt reserve was fully funded using the irrevocable letter of credit.

In addition, APCo owns the LSR Subordinate Note.

v) APMI Residual Ownership Interest

APCo's interest in Long Sault 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. The Company also has the right to acquire 58% of the equity in the facility at the end of the term of the notes in 2038.

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. 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 "*Recent Developments – 2012: 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 Facility have been obtained from the St. Lawrence Seaway Authority by way of a lease agreement with the Province of Québec. In 2009, the water rights lease was renewed for a term of 21 years commencing March 1, 2009. Although the Facility is located on a federal waterway, the Province of Quebec has asserted jurisdiction over the water rights to this Facility and has also asserted a claim against a predecessor by amalgamation to APFC for payment of revenues paid to the federal authority. See "*Legal Proceedings and Regulatory Actions – Legal Proceedings*".

(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 and Mont Laurier Facilities 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 Hydro 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 Facility is currently operating as a fixed bladed runner. Historical gross generation from the station averages 120,000 MW-hrs per year. The Facility benefits from the flow regulation of the Squa Pan Facilities, both of which are also owned and operated by APCo.

i) Transmission facilities

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.

ii) PPA

The 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 89,000 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 Facility consists of three horizontal Francis type turbines and was commissioned into commercial operation on January 16, 1992. The facility is owned by APOT.

i) PPA

The Dickson Dam PPA with TransAlta Utilities Corporation ended on January 16, 2012. Since January 17, 2012, the Facility is participating in the Alberta Power Pool selling electricity at the real time market price. APCo is exploring options to sell power to a third party and expects to put a fixed price contract in place for the output from the Facility in the second quarter of 2012.

ii) Use of Works Agreement

The 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 St. Leon Facility is Manitoba. The electricity generated by the wind turbines at the St. Leon Facility is transmitted via underground distribution lines to the facility's substation for subsequent delivery to the transmission system of the purchaser, Manitoba Hydro-Electric Board ("**Manitoba Hydro**"). The purchaser then distributes the electricity to its customers or to other endpoints via the grid.

(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.

(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.

On September 18, 2007, the St. Leon Facility achieved commercial operation pursuant to a turn-key construction contract dated November 12, 2004. 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.

i) PPA

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, 2011, 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.

ii) Credit Facility

A banking syndicate provided the AirSource Senior Debt to St. Leon Trust to finance construction of the St. Leon Facility. The AirSource Senior Debt had an amount of $67.8 million outstanding as at August 2011 when it was repaid. There is currently no debt agreement with external third parties associated with this facility.

(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.

(1) Principal Markets and Distribution Methods

See "*Material Facilities*" immediately below.

(ii) 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 to produce an average of approximately 60,000 pounds per hour of steam which is the excess of the steam required for production of internally consumed electricity. It is owned by APEFW which forms part of the APCo ownership chain.

The principal customer of the EFW facility is the Region of Peel (the " **Region**"). The facility is currently permitted to accept domestic waste from the Region of Peel and non-hazardous commercial/industrial waste from the Regions of Peel, Halton, York, Durham and the City of Toronto. In addition the facility is permitted to accept international airport waste from Pearson and Hamilton International Airports. The facility is currently working to amend its permits to accept domestic waste from all of Ontario and expects to conclude this process in 2012.

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 – 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.

i) PPA

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 OPA to enter into a new long term contract for the power output from the EFW Facility.

ii) Fuel Supply

Under a "tip or pay" waste supply agreement, the Region supplies the facility with a minimum of 127,900 tonnes per year of acceptable municipal solid waste. The EFW facility "tip or pay" waste supply agreement with the Region expires in April 2012. On February 23, 2012, the Peel Regional Council decided to seek competitive proposals from several waste management companies, including APCo. APCo is participating in this proposal process. In addition, the facility is currently permitted to accept commercial and industrial waste from certain other jurisdictions outside of the region of Peel. APCo is actively sourcing alternative supply options with respect to municipal solid waste from other jurisdictions to ensure a continued supply of waste for the 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. Six electricity products are 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 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, commissioned in 1991. The Facility is owned by Algonquin Power Sanger LLC, a subsidiary of APFA.

i) PPA

Output of the 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.

ii) Fuel Supply

Natural gas for the Facility is delivered under the terms of a gas supply agreement dated August 1, 2006 with Constellation NewEnergy for the purchase and sale of all natural gas required for the facility. The expected gas requirement for the subsequent month is bought at the market rates available on the gas nomination date, which is typically the 20th day of each month. Gas above or below the nomination requirement can be bought or sold at the applicable spot prices.

iii) Energy Lease

Pursuant to a lease, energy supply and common services agreement with Dyna Fibers Inc., a wholly-owned subsidiary of Sanger LLC, Dyna Fibers Inc. leases a portion of the facility site in order to carry on its hydro mulch business and purchases certain energy at a cost equal to a percentage of the fuel costs incurred by the 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.

iv) Credit Facility

There is an outstanding senior loan against the Facility in the amount of US $19.2 million as at December 31, 2011. 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 2010 was 1.33%. The loan is secured solely by the Facility, the ownership interests therein and an irrevocable letter of credit in an amount of US $19.5 million.

(2) Windsor Locks Facility

The Windsor Locks Facility is a 56 MW natural gas-fired generating facility located in Windsor Locks, Connecticut. The Facility is a combined cycle generating station comprised of a 40 MW General Electric natural gas fired turbine and a 16 MW General Electric steam turbine and was commissioned in 1990. The Facility is owned by Windsor LLC.

Prior to April 2010, the Facility ran at capacity, providing the steam and power requirements of Ahlstrom pursuant to the ESA with the remainder of the electrical generation being sold to CL&P. With the expiry of the PPA with CL&P, APCo determined that the existing gas turbine is not appropriately sized to meet the electrical and steam requirements of Ahlstrom.

APCo has entered into an extension of the ESA with Ahlstrom, the extended term continues until 2027, and supports the installation of a new 14 MW Solar Titan combustion gas turbine which is more appropriately sized to meet the electrical and steam requirements of the steam host. The new cogeneration equipment is being installed with commercial operation expected in

July 2012. The total expected capital cost for this project is estimated at approximately U.S. $25 million. APCo believes it is eligible to receive a one-time non-recurring grant from the State of Connecticut equivalent to U.S. $450/KW to a maximum of U.S. $6.6 million which would offset the cost of such re-powering. An additional benefit of the State of Connecticut grant program is that local distribution charges for natural gas used by the new turbine are waived, with an estimated benefit to the Facility of approximately U.S. $500,000/year.

In addition to installing the new gas turbine, APCo would expect to continue to operate the existing electrical generating equipment in the ISO NE market when it is commercially profitable to do so. APCo also believes that this project would qualify for a combined heat and power investment tax credit ("**ITC**") sponsored by the U.S. Federal Government. The benefit of the ITC grant is approximately U.S. $1 million in addition to the Connecticut DPUC grant would offset the cost of such re-powering.

i) Energy Services Agreement and Ground Lease

The Facility supplies thermal steam energy and a portion of electrical generation 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 Facility.

ii) PPA

The electrical output of the Facility not used to meet Ahlstrom's requirements is committed to the ISO-NE electricity market. Since April 2010, the Facility has bid its remaining available capacity of approximately 40 MW into the thirty minute forward operating reserve market. APCo's AES group manages the off-take sales from this Facility into the ISO-NE market.

iii) Fuel Supply

Natural gas for the facility continues to be delivered under a gas supply agreement with Yankee Gas Service Company (" **Yankee Gas**"). Gas is supplied by Yankee Gas at a percentage of its weighted average cost of gas for the month. The gas contract contains minimum annual consumption requirements with associated penalties for shortfalls. The Yankee Gas agreement was scheduled to terminate coincident with the PPA. APCo has agreed with Yankee Gas that the arrangements under the existing contract will be maintained until the new turbine is installed.

APCo and Yankee Gas continue to negotiate a new agreement that will allow the Facility to use Yankee Gas as a local distribution company which will enhance the Facility's purchase options for its natural gas requirements. It is expected that once the new turbine is installed the existing contract will be replaced by individual contracts for each of the new combustion turbine, the auxiliary boilers and the existing Frame 6 turbine. Yankee Gas is currently upgrading the gas service to accommodate the new combustion turbine.

(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 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 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 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 Facility is supplied by local forest product companies under contracts of varying terms with the longest being 25 years.

APT owns 32.4% of the Class B non-voting shares issued by Kirkland. It is Kirkland's policy to declare and pay quarterly dividends on its shares equal to substantially all of its after-tax income. Kirkland had a put option to sell the Facility to Northland with an exercise date of February 28, 2011 at an exercise price of $10 million. Further to a shareholder meeting on November 12, 2009, the Kirkland shareholders decided not to exercise the put option as the present value of the expected future dividends from this investment were expected to exceed funds they would receive from the put option. As a result, subsequent to February 28, 2011, 75% of operating income of the 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 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 Facility was commissioned in 1990 and is currently managed by Northland. Electricity produced by the Facility is sold to OEFC pursuant to a 25 year contract, which expires in 2014. The majority of the natural gas used by the 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. Cochrane had a put option to sell the Facility to Northland with an exercise date of February 28, 2011 at an exercise price of $3 million. Further to a shareholder meeting on November 12, 2009, the Cochrane shareholders decided not to exercise the put option as the present value of the expected future dividends from this investment were expected to exceed funds they would receive from the put option. As a result, subsequent to February 28, 2011, 75% of operating income of the 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 the Tinker Facility and other 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 other APCo facilities that are approaching the end of their PPAs and to engage, where possible, in actual selling of power for APCo facilities that would otherwise sell power on a merchant basis.

(i) Production Method

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

(ii) Principal Markets and Distribution Methods

AES provides energy to commercial and industrial customers in the northern Maine and New Brunswick markets. AES anticipates that, based on the expected load forecast for its existing contracts, it will provide approximately 100,000 MW-hrs of energy to its customers.

AES purchases the majority of its energy requirements 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.

In addition to the energy generation provided by the Tinker Facility, AES purchases additional energy on the open market in order to services its customer demand. APCo manages the risk associated with this business through internally generated energy from the Tinker facility, as well as through the purchase of fixed volume/prices from the ISO-NE 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.

(iii) Material Facilities

AES operates using a series of energy supply agreements. These include energy sales to a town in New Brunswick, Standard Offer Service contracts with two local electric utilities in northern Maine, and a series of direct energy contracts with commercial buyers also in northern Maine. AES has energy purchase obligations with the ISO-NE as required to supplement self-generated energy.

AES entered into a three year contract with MPS starting March 1, 2011 to provide Standard Offer Service to multiple commercial and industrial customers in Northern Maine. The anticipated annual customer load associated with the standard offer service is approximately 135,000 MW-hrs.

(f) Power Generation: Development

(i) Target Markets / Development Strategy

The Development division works to identify, develop and construct new, renewable and efficient power generating facilities, as well as to identify, develop and construct other accretive projects that maximize the potential of APCo's existing facilities. Development is focused on projects within North America with a commitment to working proactively with all stakeholders, including local communities. It utilizes existing industry relationships to assist in the identification, evaluation, development and construction of projects, and retains expertise, as required, from the financial, legal, engineering, technical, and construction sectors.

The Development division may also create opportunities through the acquisition of operating assets with accretive characteristics and prospective projects that are at various stages of development. The Development division believes that the prevailing economic climate has also created opportunities for APCo to acquire third party development projects on terms that require the experience and financial resources that APCo has at its disposal. The strategy is to focus on high quality renewable and high efficiency thermal energy generation projects that benefit from low operating costs using proven technology that can generate sustainable and increasing operating profit in order to achieve a high return on invested capital.

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 arise given that many jurisdictions, both in Canada and the U.S., continue to increase targets for renewable and other clean power generation projects. As an example, the Ontario government passed the GEA. Accordingly the OPA has issued standard pricing for electricity from renewable sources under a FIT program. Included within this legislation is the requirement for OPA to purchase power generated from green energy projects, and an obligation for all utilities to grant priority grid access to such projects. The intention of the legislation is to make development of renewable energy projects significantly easier than the prior process of formal bids in response to requests for proposals from the responsible power authority.

Other jurisdictions have passed or are considering similar legislation to provide incentives for development of new renewable power generation from independent producers. The combination of increased renewable production targets and appropriate fixed pricing will present investment opportunities for APCo to consider in the future.

APCo continues to actively pursue development projects which provide the opportunity to exhibit accretive growth. APCo anticipates its involvement in many future opportunities as initiatives designed to support independent power producers are being extensively supported by Canadian provincial governments and several U.S. states.

(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:

Project Name (Location)	Location	Size (MW)	Estimated Capital Cost	Commercial Operation	PPA Term	Production GWhr
Chaplin Wind [1]	Saskatchewan	177	$355.0	2016	25	720.0
Amherst Island [2]	Ontario	75	$230.0	2014	25	247.0
Morse Wind [3, 4]	Saskatchewan	25	$70.0	2014	20	93.0
St. Damase [1]	Quebec	24	$70.0	2013	20	86.0
Val Eo [1]	Quebec	24	$70.0	2015	20	66.0
St. Leon II [1]	Manitoba	17	$30.0	2012	25	58.0
Cornwall Solar [1, 2]	Ontario	10	$45.0	2013	20	13.4
Total		**352**	**$870.0**			**1,283.4**

Notes:
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

Subsequent to December 31, 2011, 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.

(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 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 project is currently contemplated to use efficient Class III wind turbine generator technology. APCo forecasts that the available wind resource could produce approximately 247 GWhr 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 submission of the renewable energy application is targeted for the summer of 2012. 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 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 for award of PPAs in accordance with the SaskPower Green Options Partners Program. The two 10 MW PPA's were awarded in May 2010 and the 5 MW PPA was awarded in June 2011. Upon SaskPower's approval and execution of the Kineticor PPAs, Kineticor will then assign the PPAs to APCo. All three of the projects are expected to be completed contemporaneously in early 2014.

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 2010, APCo worked with Société en Commandite Val-Éo, a community cooperative with a development project located in the Lac Saint-Jean region of Quebec, and the community of Saint-Damase to submit proposals into Hydro Quebec's 250 MW wind Request for Proposal. On December 20, 2010, both projects were awarded power purchase contracts that stipulate the use of ENERCON wind turbines.

i) Saint-Damase

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. The first 24 MW phase of the project is expected to be comprised of eight to twelve generators (depending on the cost and generating capacity of the selected wind turbine model), producing approximately 86,000 MWhr annually. Construction of the first 24 MW phase of the project is estimated to begin in early 2013 with a commercial operations date in late 2013.

The interest of APUC 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 studies of flora and fauna and the public consultation process are ongoing. Meetings were conducted July 2011 and March 2012 with participating landowners in addition to open houses to obtain additional community feedback. All major environmental authorizations are targeted for completion by the end of 2012.

ii) Val-Éo

The Val-Éo Wind Project is located in the local municipality of Saint-Gédéon de Grandmont, which is within the regional municipality of Lac-Saint-Jean-Est. The project proponents include the Val-Éo wind cooperative formed by community based landowners and APCo. The first 24 MW phase of the project is expected to be comprised of eight generators, producing approximately 66,000 MWhr annually. Construction of the first 24 MW phase of the project is expected to begin in early 2015 with commercial operations occurring in late 2015.

The interest of APUC in the project is subject to final negotiations with the 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 met, 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 with all major authorizations targeted for completion by the end of 2012.

(5) St. Leon II

In July 2011, APCo executed a 25-year PPA with Manitoba Hydro in respect of St. Leon II (a 16.5 MW expansion of APUC's existing St. Leon wind energy project located in the Province of Manitoba). Construction of this project commenced on August 30, 2011 using 10 Vestas V82 turbines. The final turbine was erected in February 2012 and the project is generating energy on all units as of March 1, 2012. The project is expected to achieve commercial operation in the second quarter of 2012. The total capital cost of the project is expected to be $29.5 million.

(6) Cornwall Solar

APCo entered into a share purchase agreement with EffiSolar to acquire all of the issued and outstanding shares of Cornwall Solar Inc. based upon the achievement of specific milestones. On December 30, 2011 OPA approval was received and the transaction closed on January 4, 2012. Cornwall Solar owns the rights to develop a 10 MWac solar project located near Cornwall, Ontario. In addition to the Cornwall project, APCo has acquired an option to acquire 10 additional Ontario based solar projects. Projects in the FIT pipeline have submitted FIT applications for an additional 100MWac.

The project has been granted an Ontario FIT contract by the OPA, with a 20 year term and a rate of $443/MWhr, resulting in expected initial annual revenues of approximately $6.2 million. The Project contemplates the use of a ground-mounted PV array system, with expected annual generation of approximately 13,400 MWh, enough to provide electricity to approximately 1,000 homes.

Following the completion of all regulatory submissions and approvals, construction of the project is expected to begin in the second half of 2012, with a Commercial Operation Date estimated in early 2013. The project is being developed on two parcels of leased land totalling approximately 138 acres.

Total capital cost of the project is targeted at approximately $45 million, which amount includes 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.

(7) Other

APCo has completed preliminary engineering and a financial feasibility analysis on a 12 MW combined cycle high efficiency thermal energy generation project located in Ontario. APCo believes this project is an excellent fit for the Minister of Energy and Infrastructure's (the "**Ministry**") Directive to procure electricity from combined heat and power projects. The Ministry is currently taking registrations from interested parties that wish to participate in such a program.

(iv) Future Development Projects – Greenfield Projects

There are a number of future greenfield development projects which are being actively pursued by the Development division. These projects encompass several new wind energy projects, hydroelectric projects at different stages of investigation, and thermal energy generation projects. The projects being examined are located both in Canada and the U.S.

(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 1% 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.

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 (South) are located in Arizona, Texas and Missouri. The Liberty Utilities (South) region’s facilities 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 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 (South) monitors the rates of return on each of its 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.

(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 Facility currently serves over 7,300 residential and commercial customers. The Gold Canyon Facility is owned by a wholly-owned subsidiary in the Liberty Utilities (South) 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 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 (South) region.

The Facility presently serves approximately 16,500 water and 18,500 wastewater customers. The wastewater facility has permitted capacity of 4.1 million gpd. The 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 customer base through a single pressure zone. In 2007, in response to high growth in connections, the Facility began preparing

design plans for expansion of its wastewater treatment facility. However, while permitting such expansion is currently underway, slowed growth has now postponed such construction plans and expansion of capacity is now anticipated to begin in 2012 or 2013, depending on local demand growth occurring. The Facility now operates at approximately 85% of design capacity. The Facility supplies Class “A+” effluent to a number of local golf courses in the area.

i) Rate Cases

On October 5, 2010, Liberty Utilities (South) received a recommended order (“ **ROO**”) for the Facility proposing an annualized revenue increase of U.S. $8.1 million. At the ACC open meeting held on December 10, 2010 to consider the ROO, the approved revenue increase was reduced to U.S. $7.1 million, with new rates effective December 1, 2010. As part of the Litchfield ROO, the rate increase will be phased in with 50% of the increase being applied in the first 6 months, increasing to 75% for 6 months thereafter, and 100% of the rate increase being realized from month 12 forward. Litchfield is entitled to recover the foregone revenue from the phase in of rates including carrying charges at 7.72%, over an approximate 18 month period, until the Company is made whole for the foregone revenue. The recovery of the foregone revenue became effective December 1, 2011 under Decision 72682.

ii) Credit Facility

The Facility currently has outstanding indebtedness to the City of Goodyear in the amount of U.S. $11.0 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, 2011 of U.S. $3.6 million bearing interest at rates between 5.85% and 5.95%. The second series was issued in 2001 with a principal amount as of December 31, 2011 of U.S. $7.1 million and bearing interest at rates between 6.3% and 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, 2011 was U.S. $1.1 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 Facility serves approximately 6,700 water and 2,200 wastewater connections in the community of Rio Rico, Arizona. The Facility is owned by a wholly-owned subsidiary of Liberty Utilities (South).

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

(4) Rate Cases—General

In 2010 and 2011, Liberty Utilities (South) completed the regulatory process with rate cases relating to a number of its facilities. Rate cases seek to ensure that a particular facility has the opportunity to recover its operating costs and earn a fair and reasonable return on its capital investment as allowed by the regulatory authority under which the facility operates. Liberty Utilities (South) monitors current and anticipated operating costs, capital investment and the rates of return in respect of each of its facility investments to determine the appropriate timing of a rate case filing in order to ensure it fully earns a rate of return on its investments.

The following table sets out some particulars with respect to the status of Liberty Water's rate cases as at March 30, 2012:

Completed Rate Cases	Date of Rate Increases	Test year	Annual U.S. $ Revenue Increase Granted
Facility			
Arizona			
Black Mountain	October 2010	June 30, 2008	$0.7 million
Litchfield	December 2010	September 30, 2008	$7.1 million
Rio Rico	February 2011	December 31, 2008	$0.9 million
Bella Vista, Northern and Southern Sunrise	April 2011	March 31, 2009	$0.7 million
Texas			
Texas Utilities (Silverleaf – 4 utilities)	October 2009	December 31, 2008	$1.2 million
Tall Timbers	July 2009	December 31, 2008	$0.2 million
Woodmark	January 2010	December 31, 2008	$0.1 million

(h) Liberty Utilities: Electrical Distribution

(i) Method of Providing Services and Distribution Methods

Electricity distribution is the final stage in the delivery of electricity to end users. A 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 and pole-mounted transformers, low-voltage (less than 1 kV) distribution wiring and sometimes electricity meters.

An electric distribution utility sources and distributes electricity it to its customers through a network of buried or overhead lines. The electricity is sourced from power generation facilities which can use various fuels such as water (hydro), natural gas, coal, biomass, 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 customer where the voltage is again lowered through a transformer for use by the customer.

The fees or rates charged for electricity are comprised of a fixed charge component plus a variable fee based on the cost for generation, transmission and distribution of the electricity. Additional fees are typically chargeable for other services such as establishing a connection, late fee, reconnections, etc.

Liberty Utilities (West)'s facility is 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 market of Liberty Utilities (West) is currently in the State of California. The utility operates under a cost-of-service regulation. The utility uses 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 (West) monitors the rates of return on its utility investment to determine the appropriate time to file a rate case 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 (West)'s California Utility is attached in Schedule D.

(1) California

The CPUC regulates electrical utilities in California. The CPUC has jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters. These regulatory bodies have the authority to establish the allowed rate of return on approved rate base and also determine which investments are approved for inclusion in the rate base which in both cases can affect the profitability of the division.

The California regulatory regime requires regular general rate case filings. This obligates any regulated utility operating in California to file a rate case every 3 years and allows for the use of a prospective test year in the establishment of rates for the utility. The CPUC also allows the use of annual adjuster mechanisms to account for inflation to labour and other expenses over the three year period of the rate case filing. In addition, a utility's rates include thresholds for capital expenditures, which once reached, can trigger adjustment mechanisms in between rate cases.

The Energy Cost Adjustment Clause ("**ECAC**") allowed in California mitigates the impact of changes in fuel prices and stabilizes earnings by allowing for the recovery of fuel and purchased power costs by updating rates charged on an annual basis. The Post Test Year Adjustment Mechanism ("**PTAM"**) allows Calpeco to update its rates annually by a cost inflation index. In addition, rates are allowed to be updated to recover the return on investment and associated depreciation of major capital projects.

(iii) Material Facility

(1) California Utility

The California Utility provides electric service to the Lake Tahoe basin and surrounding areas. The service territory, centered around a 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 customers in the seven County service territories. The customer base is heavily-weighted towards El Dorado and Placer Counties, which counties comprise approximately 89% of total revenues.

Calpeco is owned by CPUV, a 50.001% subsidiary of Liberty Utilities (West).

On April 29, 2011, pursuant to the Strategic Agreement, Emera and APUC agreed to the general terms by which Emera would sell its 49.999% indirect ownership in the California Utility to Liberty Utilities (West), with closing of such transaction subject to regulatory approval. As part of this transaction, Emera was issued 8.211 subscription receipts pursuant to the Subscription Agreement (Calpeco) and such subscription receipts will be converted into Common Shares in two tranches: 4,790,000 subscription receipts will convert into Common Shares following regulatory approval of the transfer of 100% of the California Utility to Liberty Utilities (expected in mid 2012) and the remaining 3,421,000 subscription receipts will convert into Common Shares following completion of the California Utility's first rate case, expected to be completed in early 2013.

i) Customer Base

Calpeco's customer base is primarily residential with exposure to large commercial accounts limited to under 20% of gross revenues. The existing commercial customers primarily consist of ski resorts, hotels, hospitals, schools and grocery stores with no single customer accounting for more than 3.6% of annual sales volume.

ii) Rate Case

Calpeco's most recent rate case was settled in 2009. On February 17, 2012, the California Utility filed a general rate case with the CPUC seeking, among other things, an increase of 10.0%, or $7.5 million in general rates, comprised of a $3.3 million increase in vegetation management costs, $13.0 million increase in distribution rates offset by reductions in commodity costs of $8.8 million. The rate case is for the prospective years of 2013-2015. The California Utility's proposed procedural schedule contemplates rates to be implemented on January 1, 2013.

iii) Kings Beach Generation

Calpeco 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 Kings Beach warranty.

In the event of a system outage, the Kings Beach Facility is able to provide back-up generation support to Calpeco'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 60 seconds of being activated. The facility has historically run an average of 200 hours per year.

iv) Energy Cost Adjustment Clause

ECAC is designed to recoup power supply costs that are caused by the fluctuations in the price of fuel and purchased power. The mechanism consists of a base rate and amortization rate set at the time of the general rate case. The actual power supply costs incurred by the facility are tracked and compared to the base rate power supply costs to ensure the cumulative variance

does not exceed 5%. In the event that the cumulative variance exceeds 5%, the ECAC allows for an adjustment to approved rates, reducing the commodity risk associated with the purchase of power.

v) Post Test Year Adjustment Mechanism

In years where Calpeco 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.

Calpeco 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.

vi) PPA

Calpeco has 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 has an effective starting date of January 1, 2011 with a five year renewal option. The PPA obligates NV Energy to use commercially reasonable efforts to supply Calpeco 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 resource adequacy ("RA") requirements, and designed to enable Calpeco to comply with the associated RA reporting requirements.

vii) Credit Facility

Calpeco 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.

3.3 Revenues for 2011 and 2010

As at March 30, 2012, APUC owned, directly or indirectly, debt, equity and royalty and other interests in 47 renewable generation facilities and 12 thermal generation facilities including those identified in "Other Interests in Energy Related Developments", one electrical distribution facility and 21 water distribution and wastewater facilities. For the year ended December 31, 2011, APUC derived approximately 49.8% of its revenues from its interests in power generation facilities (74.4% in 2010), 5.9% of its revenues from waste disposal fees (4.9% in 2010), 28.0% of its revenues from electrical distribution and 16.3% of its revenues from its interests in water distribution and wastewater facilities (20.7% in 2010).

3.4 Specialized Skill and Knowledge

The senior executives of APUC have extensive contacts in the independent power industry in Canada and the United States. APCo, as well, has 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.

The electrical distribution service business of Liberty Utilities (West) requires specialized knowledge of electrical utility distribution systems and its various components. Liberty Utilities (West) has contracted the services of 41 employees that previously operated and maintained the California Assets electrical distribution network. In addition Liberty Utilities (West) has also recruited an additional 35 qualified individuals to work in the service territory in various capacities, including Lineman, Customer Service and Financial. In late 2011, Liberty Utilities (West) hired a new regional president with over 30 years of electric utility experience.

In anticipation of the acquisitions of Granite State, Energy North and the Midwest Gas Utilities, in 2012, an experienced utility team has been recruited to support procurement of both natural gas and electricity by the utilities owned by Liberty Utilities. As with the acquisition of the California Assets, Liberty Utilities intends to contract the services of the existing operating personnel necessary to run the these new organizations as part of the completion of these acquisitions.

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

3.5 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.

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 power is not subject to commodity fuel price volatility or risk. In addition, the generation of hydroelectric power does not involve significant ongoing capital and operating costs to ensure strict compliance with environmental regulations, which is a significant advantage over power generated by burning waste or utilizing landfill gases.

Deregulation has increased demand for privately generated power from a variety of sources including fossil fuels, waste, wind and water. Taking into account capital costs, wind power is

generally more expensive than traditional forms of generated power. Fossil fuels are harmful to the environment, and waste burning power generation requires producers to abide by stringent and costly environmental regulations.

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.

Though programs and policies are evolving at all government levels, the trading of greenhouse gas credits created by renewable energy projects is seen as part of the eventual solution.

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.

Liberty Utilities is the holding company for APUC's utilities businesses. The primary focus of Liberty Utilities is the acquisition of regulated utilities in the water, wastewater, electric transmission and distribution and natural gas distribution businesses. These businesses have geographic monopolies in their service territories and are therefore insulated from competition. Liberty Utilities has developed in-house significant regulatory expertise in order to effectively deal with the state regulators in the various jurisdictions in which it operates.

3.6 Environmental Protection

The APUC Businesses encompass operations which require adherence to environmental standards imposed by regulatory bodies through licences, permits, policies and legislation. Failure to operate the APUC Businesses in strict compliance with these regulatory standards may expose the APUC Businesses to claims, clean-up costs 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, 2011. 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. APUC has assessed the likelihood of these risks becoming a contingent environmental liability as remote; therefore APUC has not recorded any contingent liabilities on its financial statements.

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. In the aggregate, the departments comprise 12 full time equivalent positions and have an annual budget of approximately $1.6 million, which includes wages, travel and other costs. Facility specific permitting and compliance expenses are direct operating expenses of each facility and are excluded from these expenses.

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. Each of APUC's businesses have 24 hour, 365 day emergency response and spill procedures in place in the event there is an oil or chemical spill.

3.7 Employees

APUC has 15 employees involved in the management of the corporation. APCo currently has 77 employees who are involved in the operation of the renewable energy facilities, 16 employees who provide technical, environmental and safety services to APCo, an additional 43 employees through its subsidiaries who are involved in the operations of the thermal Facilities, 29 employees who are involved in management and 5 employees involved in energy marketing. Labour relations have been stable to date and there has not been any disruption in operations as a result of labour disputes with employees. With the exception of 48 employees at the EFW Facility and 6 employees at the Tinker Facility, the employees of APCo entities are non-unionized.

Liberty Utilities, which provides managerial expertise to Liberty Utilities (South) and Liberty Utilities (West) currently has 28 employees. In addition, Liberty Utilities (South) currently has 136 employees. Liberty Utilities (West) currently employs approximately 77 employees. With the exception of 49 employees at the California Utility, the employees of Liberty Utilities employees are non-unionized

3.8 Foreign Operations

At the current exchange rate, approximately 55% of expected EBITDA in 2012 and 65% of cash flow from operations is generated in U.S. dollars. APUC has interests in hydroelectric, thermal, electric distribution, water distribution and wastewater treatment facilities located in the United States.

Currency fluctuations may affect the cash flow that APUC will realize from its operations, as certain APUC Businesses sell electricity in the United States and receive proceeds from such sales in US dollars. Such APUC Businesses also incur costs in US dollars.

3.9 Cycles and Seasonality

Based on the type of PPAs in place at all of the facilities in which APUC has an interest, the revenue generated by the facilities is proportional to the amount of electrical energy generated.

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 the 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. 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 any wind farm. 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, in the Liberty Utilities (South) region, 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 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

For Liberty Utilities, demand for and consumption of electrical energy is primarily affected by weather conditions and to a smaller degree conservation initiatives. Above normal snowfall, with lower temperatures in the Lake Tahoe area brings more ski resort tourists with an increased and consumption of demand for electricity by our customers. Liberty Utilities provides information and programs to its customers to encourage the conservation of energy. In turn, demand for and consumption of electrical energy may be reduced in the case of a mild winter (light snowfall & warmer winter) which could have adverse impacts to revenues. Liberty Utilities provides information and programs to its customers to encourage the conservation of energy.

3.10 Customers

The APUC Businesses derive their revenues principally from the sale of electricity to large utilities. For the twelve months ended December 31, 2011, APUC Businesses' revenues were derived as follows: Hydro-Québec—approximately 8.4%; Manitoba Hydro—approximately 8.1%; PG&E – approximately 5.3%; electricity sales facility – approximately 28.0%; water distribution and wastewater treatment facilities – approximately 16.3%; waste disposal fees – approximately 5.9% and others—approximately 26.9%.

3.11 Economic Dependence

The largest customer on a percentage basis is Hydro-Québec which totalled 8.4% of gross revenues in the year ended December 31, 2011. This customer maintains an A+ S&P rating and receivables are invoiced monthly and generally collected within 20 days.

Similarly, the second largest customer on a percentage basis is Manitoba Hydro which totalled 8.1% of gross revenues in the year ended December 31, 2011. This customer maintains an AA 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.

3.12 Social or Environmental Policies

APUC has safety and environmental compliance policies in place. These policies have been communicated with staff, and have been incorporated into APUC's Safety Mission Statement and Employee manual.

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.

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 Treasury Risk Management

APUC attempts to proactively manage the risk exposures of its subsidiaries in a prudent manner. APUC ensures that each of APCo, Liberty Utilities (South) and Liberty Utilities (West) 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 55% of EBITDA and 65% 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 increased reported revenue from U.S. operations of approximately $5.4 million ($0.05 per share) on an annual basis.

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

(i) Liberty Utilities

Liberty Utilities has operations in the U.S., incurs the majority of its operating costs in U.S. currency and generates all of its revenue from utility services in U.S. dollars. Liberty Utilities uses U.S. dollar long term debt as part of its capital structure. As such, Liberty Utilities has minimal foreign currency risk arising from U.S./Canadian currency fluctuations, with the exception of corporate head office charge backs based in Canadian dollars.

(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 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.

Liberty Utilities (South) and Liberty Utilities (West)

There is no 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, net receivable 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

APCo does not believe this risk to be significant as approximately 82% of Renewable Energy division's revenue, approximately 48% of APCo Thermal Energy division's revenue, and over 68% of APCo's total revenue is earned from large utility customers having a credit rating of BBB or better, and revenue is generally invoiced and collected within 45 days.

The following chart sets out APCo's significant counterparties, their credit ratings and percentage of total revenue associated with the counterparty:

Counterparty	Credit Rating *	Approximate Annual Revenues	Percent of Divisional Revenue
Renewable Energy Division			
Hydro – Quebec	A+	23,200	26%
Manitoba Hydro	AA	22,400	25%
Ontario Electricity Financial Corporation	A+	11,000	12%
MPS**	BBB+	6,600	7%
TransAlta Corp – Dickson Dam	BBB	4,000	5%
Public Service Company of New Hampshire	BBB	3,200	4%
National Grid	A-	3,000	3%
Total		**$ 73,400**	**82%**
Thermal Energy Division			
Regional Municipality of Peel	AAA	16,400	25%
Pacific Gas and Electric Company	BBB+	14,600	23%
Total		**$ 31,000**	**48%**

* Ratings by Dunn & Bradstreet or Standard & Poor's as of February 2012.

** MPS is a subsidiary of Emera. Emera is rated BBB+.

Liberty Utilities (South)

Liberty Utilities (South) does not believe this risk to be significant as approximately 75% of revenue are generated from the residential customer base and exposure to large commercial accounts is limited to less than 20% of gross revenues. The residential customer base provides a source of stable cashflows thereby further reducing credit/counterparty risk. Credit risk related to Liberty Utilities (South) accounts receivable balances of U.S. $5.1 million at December 31, 2011 is spread over approximately 76,000 customers, resulting in an average outstanding balance of approximately $70.00 per customer. In addition, no single customer accounts for more than 3.5% of annual sales volume.

Liberty Utilities (West)

Liberty Utilities (West) does not believe this risk to be significant as over 50% of revenue is generated from the residential customer base and exposure to large commercial accounts is limited to less than 20% of gross revenues. The residential customer base provides a source of stable cashflows thereby further reducing credit/counterparty risk. The existing commercial customer base primarily consist of ski resorts, hotels, hospitals, schools and grocery stores, which tend to exhibit characteristics similar to residential accounts (predictable usage patterns, low attrition, etc.). In addition, no single customer accounts for more than 3.6% of annual sales volume.

Credit risk is monitored on an ongoing basis with processes in place to check and evaluate this risk including background credit checks and security deposits from new customers.

(d) Interest rate risk

APCo

APCo has a number of project specific and other debt facilities that are subject to a variable interest rate. These facilities and the sensitivity to changes in the variable interest rates charged are discussed below:

- The APCo Facility has no amounts outstanding as at December 31, 2011. As a result, a 100 basis point change in the variable rate charged would not impact interest expense.
- APCo's project debt at the St. Leon facility had a balance of $67.8 million as at June 30, 2011. The outstanding balance was repaid during the quarter ended September 30, 2011 using proceeds from the Senior Unsecured Debenture offering. Accordingly there is no further interest rate risk associated with this debt facility.
- APCo's project debt at its Sanger cogeneration facility has a balance of U.S. $19.2 million as at December 31, 2011. 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.

Liberty Utilities

As at December 31, 2011, Liberty Utilities has minimal exposure to interest rate risk.

Liberty Utilities (South) has existing project debt at the Litchfield and Bella Vista Facilities which are subject to a fixed rate of interest and thus is not subject to interest rate risk. Liberty Utilities (South) has fixed rate senior unsecured private placement borrowings of U.S. $50 million which is not subject to interest rate risk.

Liberty Utilities (West) has fixed rate senior unsecured private placement borrowings of U.S. $70 million which is not subject to interest rate risk.

Liberty Utilities has a senior debt facility that is subject to a variable interest rate. The facility and the sensitivity to changes in the variable interest rates charged are discussed below:

- The Liberty Facility has no amounts outstanding as at March 30, 2011. As a result, a 100 basis point change in the variable rate charged would not impact interest expense.

(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.

APCo

APCo's approach to managing liquidity risk is to ensure, to the extent possible, that it will always have sufficient liquidity to meet liabilities when due.

During 2011, APCo concluded negotiations with its bank syndicate on the renewal of the APCo Facility. APCo also reduced the total of the APCo Facility to $120 million following the completion of the Senior Unsecured Debenture offering of APCo in July 2011.

As at December 31, 2011, no amounts had been drawn on the APCo Facility. In addition to amounts actually drawn, there were $39.6 million in letters of credit outstanding as at December 31, 2011, resulting in APCo having $80.4 million of committed and available bank facilities.

The cash flow generated from several of APCo'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 APCo losing its investment in such operating facility. APCo actively manages cash availability at its operating facilities to ensure they are adequately funded and minimize the risk of this possibility.

Liberty Utilities

On January 19, 2012, Liberty Utilities concluded negotiations with its bank syndicate on entering into the Liberty Facility, a senior unsecured revolving credit facility. The Liberty Facility provides Liberty Utilities with sufficient liquidity to manage the short term working capital needs of its operations or allow investments in property, plant and equipment.

As the long term borrowings at Liberty Utilities (South) do not mature until 2020 and beyond and the long term borrowings at Liberty Utilities (West) do not mature until 2020 and 2025, there is no immediate liquidity risk associated with the long term debt.

Senior unsecured notes and project specific debt for Liberty Utilities (South) totals approximately U.S. $64 million. In the event that there is a breach of covenants or obligations with regard to any of the project specific debt which was not later remedied, the project level debt could go into default which could result in the lender realizing on its security and the company losing its investment in the respective operating facility.

Liberty Utilities actively manages both the cash availability in its regions and funds available under the Liberty Facility to ensure its operations 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 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 $0.1 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 an increase in net revenue by approximately $1.4 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 130,000 MW-hrs in fiscal 2012. While the Tinker facility is expected to provide the majority 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 $1.3 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 70,000 MW-hrs of net energy over the next 12 months at an average rate of approximately U.S. $50 per MW-hr. The mark-to-market value of these forward energy purchase contracts at December 31, 2011 was a net liability of U.S. $1.2 million.

Liberty Utilities (South)

Liberty Utilities' water distribution and wastewater collection and treatment utility systems are not subject to any material commodity price risk.

Liberty Utilities (West)

Liberty Utilities (West) provides electric services to the Lake Tahoe basin and surrounding areas at rates approved by the CPUC. Liberty Utilities (West) purchases the energy requirements for its customers from NV Energy at rates reflecting its system average costs. In the event that these rates change, each $10.00 change per MW-hr would result in a change in expense of approximately U.S. $6.5 million on an annualized basis.

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.

(g) Risk of Default under Senior Credit Facility

APCo

As security for repayment of the APCo Facility, APCo has, among other things, pledged the shares and other equity interests of certain of its subsidiaries. In addition to any amounts outstanding under the APCo Facility as described above, APCo has posted certain letters of credit totaling $39.6 million as security for obligations of the APCo businesses. The terms of the APCo Facility require APCo to pay a standby charge calculated as one quarter of the current stamping fee on the unused portion of the Senior Credit Facility and maintain certain financial covenants.

If the APCo Facility goes into default, or is not renewed or refinanced when due, there is a risk that the lenders could exercise their security.

Liberty Utilities

The Liberty Facility is unsecured. In addition to any amounts outstanding under the Liberty Facility as described above, Liberty Utilities has posted certain letters of credit totaling $1.2 million as security for obligations of the Liberty businesses. The terms of the Liberty Facility require Liberty Utilities to pay a standby charge calculated as one quarter of the current stamping fee on the unused portion of the Liberty Facility and maintain certain financial covenants.

Liberty Utilities manages its operational cash flow and its availability under the Liberty Facility to meet such payment obligations. If the Liberty Facility goes into default, or is not renewed or refinanced when due, there is a risk that the lenders could exercise their rights to accelerate Liberty Utilities repayment obligations under the facility.

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 dependence upon APUC Businesses, regulatory climate and permits, tax related matters, gross capital requirements, labour relations, reliance on key customers and environmental health and safety considerations. The risks discussed below are not intended as a complete list of all exposures that APUC and its subsidiaries may encounter.

(a) Mechanical and Operational Risks

APUC is entirely dependent upon the operations and assets of each of APUC's Businesses. Accordingly, dividends to shareholders are dependent upon the profitability of each of APUC's Businesses. This profitability could be impacted by equipment failure, the failure of a major customer to fulfill its contractual obligations under its PPA, reductions in average energy prices, a strike or lock-out at a facility and expenses related to claims or clean-up to adhere to environmental and safety standards.

APCo

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

Liberty Utilities (South)

Liberty Utilities (South)'s 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.

The water distribution networks 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.

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.

Liberty Utilities (West)

Electricity distribution systems are subject to storm events, usually winter storm events, whereby power lines can be brought down by high winds, tree branches, and even complete trees with the attendant risk to individuals and property. In addition, in forested areas during dry weather years, 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.

(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's businesses do not have any significant retirement obligation liabilities and APUC has not recorded any liability in its financial statements.

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 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 EFW Facility owns the property on which its facility operates. EFW's current waste incineration agreement with the Region expires in April 2012. On February 23, 2012, the Peel Regional Council decided to seek competitive proposals from several waste management companies, including APCo. APCo is participating in this proposal process. In addition, the facility is currently permitted to accept commercial and industrial waste from certain other jurisdictions outside of the Region of Peel. APCo is actively sourcing alternative supply options with respect to municipal solid waste from other jurisdictions to ensure a continued supply of waste for the facility.

While APCo anticipates being in a position to renew or extend the existing contract in 2012, in the event that APCo is unable to renew or extend the agreement, APCo may choose to close the facility but has no legal obligation to remove the assets. Under the terms of the contract, the responsibility for removal of the bulk of any hazardous material generated in the operation of the facility remains with EFW's primary customer. As such, the potential expense to bring the facility in line with current environmental standards in the event it is eventually closed has been assessed as insignificant based on the quantification of costs to remediate the facility, expectation that the existing contract can be extended or renewed and that the potential timing of such an event, although unlikely, would be well in the future.

Liberty Utilities (South)

Liberty Utilities (South)'s 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 (South) 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 (South) is allowed to earn a return on its investment

Liberty Utilities (West)

Liberty Utilities (West) 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 (West) 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 (West) 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 (South)

Liberty Utilities (South)'s water distribution and wastewater collection and treatment utility systems face 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 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 (South) 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 (South) 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.

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 (West)

Liberty Utilities (West) faces environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of an electrical distribution system are related to potential accidental release of mineral oil to the environment from non-operational events and the management of hazardous and universal waste in accordance with the various Federal, State and local environmental laws. Like most other industrial companies, Liberty Utilities (West) 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 (West) 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

(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 – Power Generation**

Several north-eastern U.S. States have formed a coordination group to develop a multi-state green house 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 will be implemented to regulate CO_2 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. As such APCo will be required to purchase approximately 250,000 tons of CO_2 allowances per year, equivalent to the total annual CO_2 emissions from the Windsor Locks facility for the 2009 to 2012 fiscal years. APCo is entitled to apply for allowances and/or purchase allowances at a base price of $2.00 per tonne from the state of Connecticut. APCo submitted an application on October 31, 2008 for allowances under the available programs. For 2012, APCo has currently estimated the cost of compliance with the RGGI requirements for the Windsor Locks Facility to be between $0.2 and $0.4 million.

RGGI has been in effect in CT since 2009. The first compliance period is from January 2009 to December 2011. For 2012, it is estimated that the Facility will produce 100,000 tons of CO_2, obtain allowances of 55,000 tons through the UTSA, and be required to purchase an additional 55,000 tons to comply with RGGI by the end of December. The current price for RGGI allowances is approximately $1.90/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. 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 others in Ontario which could be impacted by this program.

The EFW Facility submitted the first GHG report under the Ontario Regulation 452/09 in June 2011. In the future, APEFW will also be required to purchase emissions allocations based on emissions reported for the 2010 and/or subsequent periods, depending on the timing for the implementation of the Provincial Cap-and-Trade program, still under final design and approval.

The State of California is the first member of the WCI to implement a Cap-and-Trade program. This program started on January 1, 2012, with the first enforceable compliance obligation beginning with 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.

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 $57.0 trillion of 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 submitted a baseline greenhouse gas emissions inventory to the CDP for 2008, 2009 and 2010. The inventory is presently being done for 2011. 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) **APCo—Greenhouse Gas Initiatives – Renewable Energy**

As a result of certain legislation passed in Québec (Bill C93), APCo is undertaking technical assessments of its hydroelectric facility dams owned or leased within the Province of Québec.

The province of Ontario is considering enacting new legislation similar to Bill C93. APCo operates four 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 expected capital costs related to the Québec Facilities, as there are fewer facilities in Ontario and they are of newer construction.

(iii) **Liberty Utilities (South)**

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 closely 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. Additional remedial efforts by the EPA to stop advancement and reduce TCE concentrations are

continuing. 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 of removal of a well, 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 (South) does not believe it is exposed to a material liability and has not recorded a contingent environmental liability on its financial statements.

The Company'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, 2011.

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

APCo

As a result of certain legislation passed in Quebec (Bill C93), APCo is undertaking technical assessments of its hydroelectric facility dams owned or leased within the Province of Quebec. See "*Specific Environmental Risks*" under "*Risk Factors*".

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 Calpeco. Any increases in cost of electricity will be passed on the ratepayers through the General Rate Case process.

(v) **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.

(f) Litigation risks and other contingencies

APUC and certain of its subsidiaries are involved in various lawsuits, 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

As discussed below under "*Legal Proceedings and Regulatory Actions – Legal Proceedings* ", APCo and Algonquin Power Corp. ("APC"), an affiliate of APMI, are involved in civil proceedings and bankruptcy proceedings with Trafalgar. As also discussed in that section, the Attorney General of Québec ("**Québec AG**") filed suit claiming that an Algonquin entity had been paying to the federal authority under its water lease. Both proceedings have gone to the appeal stage. On the Trafalgar civil proceedings file, the claims against APCo were dismissed on appeal, and the bankruptcy proceedings continue. On the Côte Ste-Catherine Water Lease Dues file, the appeal was heard in January 2011 and on October 21, 2011 the Québec Court of Appeal allowed the appeal and condemned the APUC subsidiary to pay approximately $5.4 million which includes the amount claimed with interest.

(g) 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.

(h) 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.

(i) Obligations to Serve

APCo

APCo is not subject to obligations to serve.

Liberty Utilities

Liberty Utilities facilities may be 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 (South) and Liberty Utilities (West) 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 electrical generating facilities. 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.

The US Thermal Facilities obtain certain benefits and exemptions because of their Qualifying Facility status (“ **QF Status**”) under PURPA. If any facility were to lose its QF Status, the Facility would no longer be entitled to the exemptions and benefits thereof. Loss of QF Status may also require the Facility to cease selling electricity at the rates set forth in the existing PPAs to the extent they exceed current short run Avoided Costs. Under certain circumstances, loss of QF Status on a retroactive basis could lead to, among other things, claims by an electrical utility’s end user customers for a refund of payments previously made.

Liberty Utilities (South)

Liberty Utilities (South) water distribution and wastewater collection and treatment 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 water and wastewater utility operations. Operating costs could be significantly affected in order to comply with new or stricter regulatory requirements.

Water and wastewater 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 (South), and while Liberty Utilities (South) 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 (South) regularly works with these authorities to manage the affairs of the business.

Liberty Utilities (West)

Liberty Utilities (West)'s facilities are subject to rate setting by State regulatory agencies. The time between the incurrence of costs and the granting of the rates to recover those costs by State regulatory agencies is known as regulatory lag. As a result of regulatory lag, inflationary effects may impact the ability to recover expenses, and profitability could be impacted. Federal, State and local environmental laws and regulations impose substantial compliance requirements on electricity distribution utilities. Operating costs could be significantly affected in order to comply with new or stricter regulatory requirements.

Electricity distribution utilities could be subject to condemnation or other methods of taking by government entities under certain conditions. While any taking by government entities would require compensation be paid to Liberty Utilities (West), and while Liberty Utilities (West) 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 (West) regularly works with these authorities to manage the affairs of the business.

4.4 Dependence upon APUC Businesses

APUC

Liberty Utilities has reduced its dependence on APUC through initiatives such as obtaining a senior unsecured revolving credit facility, the Liberty Facility, issuing long term debt directly on its own and placement of regional presidents to oversee operations. 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.

APCo

The profitability of APCo may be affected by expiry of the present long-term PPAs to which certain of APCo's subsidiaries are a party.

Liberty Utilities

US governmental authorities have the ability to impose restrictions on water and electricity usage during periods of drought or power generation disruption and loss of adequate transmission capability, respectively. If imposed, this could result in decreased demand for water and electricity, even if supplies are adequate, which could adversely affect revenues and earnings.

Water and electricity distribution and wastewater treatment facilities could also 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 (South) and Liberty Utilities (West), and while both Liberty Utilities (South) and Liberty Utilities (West) believe 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.

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 (South)

All employees of Liberty Utilities (South) and their material subcontractors are non-unionized.

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 was renegotiated in August 2010 for a term of three years, until August 2013.

4.7 Dependence Upon Key Customers

APCo

The customers that currently purchase APUC's Facilities are primarily large utilities. See the summaries of the contracts in Schedules A, B, C and D. If, for any reason, such customers were unable to fulfill their contractual obligations under the PPAs, cash flow available to Shareholders would decline.

Liberty Utilities (South)

The customers of Liberty Utilities (South) water and wastewater utilities are primarily residential. Large commercial and industrial customers make up less than 24% of gross revenues, with no single customer making up more than 2.4% of gross revenues. As such, the Company has minimal dependence upon a few key customers.

Liberty Utilities (West)

The customers that currently purchase from Liberty Utilities (West) facilities are primarily residential. Large commercial accounts make up less than 20% of gross revenues, with no single customer making up more than 3.6% of gross revenues. As such, the Company has minimal dependence upon a few key customers.

4.8 Potential Conflicts of Interest

As discussed in "*Three Year History – Fiscal 2009*" above, an agreement was reached on December 21, 2009 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 Algonquin 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, 2011.

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

The total amount of dividends declared for fiscal 2009, 2010 and 2011 were $19.3, $22.8 million and $32.4 million, respectively. The amount of dividends declared for each Common Share of APUC for fiscal 2009, 2010 and 2011 were $0.24, $0.24 and $0.27, respectively.

APUC follows a quarterly dividend schedule, subject to subsequent Board declarations each quarter. Effective August 11, 2011, the Board established a quarterly dividend of $0.07 or $0.28 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*".

5.1 Dividend Reinvestment Plan

Effective October 1, 2011, APUC introduced a shareholder dividend reinvestment plan (the " **Reinvestment Plan**") which will be offered to registered holders of Common Share ("**Shareholders**") 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 December 31, 2011, 23.6 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, 2011, APUC had 136,122,780 issued and outstanding Common Shares. Following the Series 2A Redemption, APUC had 146,741,635 Common Shares outstanding.

As at December 31, 2011, the 12.0 million subscription receipts issued to Emera pursuant to the Subscription Agreement (National Grid) convertible into 12.0 million Common Shares was outstanding. Delivery of the Common Shares under the subscription receipts is conditional on and is planned to occur simultaneously with the closing of the acquisition of Granite State and EnergyNorth. The proceeds of the subscription receipts are to be utilized to fund a portion of the cost to acquire Granite State and EnergyNorth.

On April 29, 2011, pursuant to the Strategic 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 dated September 12, 2011 (the "**Subscription Agreement (Calpeco)**") with APUC, pursuant to which Emera subscribed for an aggregate of 8,211,000 subscription receipts from APUC 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 proceeds of this subscription receipt transaction will be used to fund the acquisition by Liberty Utilities of Emera US Holdings Inc.'s interest in the California Utility. 4,790,000 subscription receipts will convert into APUC shares on a one-for-one basis following regulatory approval of the transfer of 100% of the California Utility to Liberty Utilities (expected in early 2012), at which time the $22,608,800 promissory note delivered by Emera to APUC to satisfy the subscription price of the first tranche of subscription receipts become due and payable. The remaining 3,421,000 subscription receipts will convert into APUC shares on a one-for-one basis following completion of the California Utility's first rate case, expected to be completed in early 2013, at which time the $16,147,120 promissory note delivered by Emera to APUC to satisfy the subscription price of the second tranche of subscription receipts become due and payable. In the event of termination of the Subscription Agreement (Calpeco), the promissory notes will be returned to Emera for cancellation, the subscription receipts will be returned to APUC for cancellation, and the parties will have no further obligations under the Subscription Agreement (Calpeco).

On April 30, 2011, APUC committed to issuance to Emera of a treasury subscription of subscription receipts convertible into approximately 6.9 million APUC common shares upon closing of the transaction related to the acquisition of an interest in a portfolio of 370MW wind projects. APUC intends to cancel this treasury subscription as it announced on January 27, 2012 that it no longer intended to proceed with the First Wind acquisition.

6.2 Preferred Shares

APUC is authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board. APUC does not have any issued and outstanding preferred shares.

6.3 Convertible Debentures

APUC currently has outstanding series of convertible debentures:

- a principal amount of $62,800 Series 3 Debentures.

If all of the principal amount of the Series 3 Debentures were converted by the holders thereof, an additional 14,882,142 Common Shares will be issued pursuant to the terms of the trust indenture (the "**Series 3 Trust Indenture**") dated as of December 2, 2009 between APUC and the Debenture Trustee.

(a) Series 1A Debentures

On October 27, 2009, the Corporation issued, in connection with the Unit Exchange, an aggregate of $66,942,750 principal amount of 7.50% convertible unsecured subordinated debentures due November 33, 2014 (the "**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 Redemption Date, a principal amount of $60,339,000 of Series 1A Debentures were converted into 14,788,975 Common Shares. On the Redemption Date, APUC issued and delivered 430,666 Common Shares to the remaining holders of the Series 1A Debentures, representing the number of freely tradeable Common Shares obtained by dividing the aggregate principal amount of Debentures, by 95% of the current market price of Common Shares on the Redemption Date.

As a result of the Redemption there were no Series 1A Debentures outstanding subsequent to the 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 debentureholders 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 tradeable 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. The Series 3 Debentures bear interest at 7.0% per annum, payable semi-annually in arrears on June 30 and December 30 each year. As at March 15, 2012, there were $62,505,000 principal amount of Series 3 Debentures outstanding.

APUC may, from time to time, without the consent of the holders of the APUC Debentures, issue additional debentures. For a complete description of the APUC Debentures, reference should be made to the Trust Indenture and the Series 3 Trust Indenture, copies of which are available on www.sedar.com.

(i) Conversion Privilege

The Series 3 Debentures are convertible at the holder's option into fully paid, non-assessable and freely tradeable Common Shares at any time prior to 5:00 p.m. (Toronto time) on the earlier of June 30, 2017 (the "**Series 3 Maturity Date**") and the business day immediately preceding the date specified by APUC for redemption of the Series 3 Debentures, at a conversion price of $4.20 per Common Share (the "**Series 3 Conversion Price**") being a ratio of approximately 238.1 Common Shares per $1,000 principal amount of Series 3 Debentures. The Series 3 Debentures bear interest from the date of issue at 7.0% per annum, which will be payable semi-annually on June 30 and December 31 in each year, commencing on June 30, 2010 (each, a "**Series 3 Interest Payment Date**").

Interest will be payable based on a 365-day year. At the option of APUC, subject to applicable law, APUC may deliver Common Shares to its agent who shall sell such Common Shares on behalf of APUC in order to raise funds to satisfy all or any part of APUC's obligations to pay interest on the APUC Debentures, but in any event, the holders of APUC Debentures shall be entitled to receive cash payments equal to the interest otherwise payable on the APUC Debentures.

No adjustment will be made for dividends on Common Shares issuable upon conversion or for interest accrued on APUC Debentures surrendered for conversion; however, holders converting their APUC Debentures are entitled to receive, in addition to the applicable number of Common Shares, accrued and unpaid interest in respect thereof for the period up to the date of conversion from the latest Series 3 Interest Payment Date in the case of the Series 3

Debentures. Notwithstanding the foregoing, no Series 3 Debentures may be converted on any Series 3 Interest Payment Date and during the five business days preceding June 30 and December 31 in each year as the registers of the Debenture Trustee are closed during such periods.

Subject to the provisions thereof, the Series 3 Trust Indenture provide for the adjustment of the Series 3 Conversion Price in certain events including: (a) the subdivision or consolidation of the outstanding Common Shares; (b) the distribution of Common Shares to holders of Common Shares by way of distribution or otherwise other than an issue of securities to holders of Common Shares who have elected to receive distributions in securities of APUC in lieu of receiving cash distributions paid in the ordinary course; (c) the issuance of options, rights or warrants to holders of Common Shares entitling them to acquire Common Shares or other securities convertible into Common Shares at less than 95% of the then Current Market Price (as defined below under "Payment upon Redemption or Maturity") of the Common Shares; and (d) the distribution to all holders of Common Shares of any securities or assets (other than cash distributions and equivalent distributions in securities paid in lieu of cash distributions in the ordinary course). There will be no adjustment of the Series 3 Conversion Price, in respect of any event described in (b), (c) or (d) above if, subject to prior regulatory approval, the holders of APUC Debentures are allowed to participate as though they had converted their APUC Debentures prior to the applicable record date or effective date. APUC will not be required to make adjustments the Series 3 Conversion Price, unless the cumulative effect of such adjustments would change the Series 3 Conversion Price, as the case may be, by at least 1%.

In the case of any reclassification or change (other than a change resulting only from consolidation or subdivision) of the Common Shares or in case of any amalgamation, consolidation or merger of APUC with or into any other entity, or in the case of any sale, transfer or other disposition of the properties and assets of APUC as, or substantially as, an entirety to any other entity, the terms of the conversion privilege shall be adjusted so that each APUC Debenture shall, after such reclassification, change, amalgamation, consolidation, merger or sale, be exercisable for the kind and amount of securities or property of APUC, or such continuing, successor or purchaser entity, as the case may be, which the holder thereof would have been entitled to receive as a result of such reclassification, change, amalgamation, consolidation, merger or sale if on the effective date thereof it had been the holder of the number of Common Shares into which APUC Debenture was convertible prior to the effective date of such reclassification, change, amalgamation, consolidation, merger or sale.

No fractional Common Shares will be issued on any conversion of APUC Debentures, but in lieu thereof, APUC shall satisfy such fractional interest by a cash payment equal to the Current Market Price of such fractional interest.

(ii) Redemption and Purchase

The Series 3 Debentures may not be redeemed by APUC (except in the case of a change of control) on or before December 31, 2012. Thereafter, but prior to December 31, 2014, the Series 3 Debentures may be redeemed at the option of APUC, in whole at any time or in part from time to time, on not more than 60 days' and not less than 30 days' prior notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest, provided that the weighted average trading price of the Common Shares on the TSX for the 20 consecutive trading days ending five trading days preceding the date on which notice of redemption is given exceeds 125% of the Series 3 Conversion Price.

On or after December 31, 2014 and prior to the Series 3 Maturity Date, the Series 3 Debentures may be redeemed by APUC, in whole or in part from time to time, on not more than 60 days' and not less than 30 days' prior notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest.

APUC will have the right to purchase APUC Debentures in the market, by tender or by private contract subject to regulatory requirements; provided, however, that if an Event of Default (as defined below) has occurred and is continuing, APUC will not have the right to purchase APUC Debentures by private contract.

In the case of redemption of less than all of APUC Debentures, APUC Debentures to be redeemed will be selected by the Debenture Trustee on a pro rata basis or in such other manner as the Debenture Trustee deems equitable, subject to the consent of the TSX.

(iii) Payment upon Redemption or Maturity

On redemption or on the Series 3 Maturity Date, as applicable, APUC will repay the indebtedness represented by APUC Debentures which are to be redeemed or which have matured by paying to the Debenture Trustee in lawful money of Canada an amount equal to the principal amount of the outstanding APUC Debentures, together with accrued and unpaid interest thereon. APUC may, at its option, on not more than 60 days' and not less than 40 days' prior notice and subject to any required regulatory approvals, unless an Event of Default (as defined below) has occurred and is continuing, elect to satisfy its obligation to repay, in whole or in part, the principal amount of APUC Debentures which are to be redeemed or which have matured by issuing and delivering freely tradeable Common Shares to the holders of the APUC Debentures. The number of Common Shares to be issued will be determined by dividing the principal amount of the APUC Debentures which are to be redeemed by 95% of the Current Market Price of the Common Shares on the date fixed for redemption or the maturity date, as the case may be. No fractional Common Shares will be issued to holders of APUC Debentures but in lieu thereof APUC shall satisfy such fractional interest by a cash payment equal to the Current Market Price of such fractional interest.

The term "**Current Market Price**" is defined in the Series 3 Trust Indenture to mean the weighted average trading price of the Common Shares on the TSX for the 20 consecutive trading days ending on the fifth trading day preceding the date of the applicable event.

(iv) Cancellation

All APUC Debentures converted, redeemed or purchased as aforesaid will be cancelled and may not be reissued or resold.

(v) Subordination

The payment of the principal of, and interest on, the APUC Debentures is subordinated in right of payment, in the circumstances referred to below and more particularly as set forth in the Trust Indenture, to the prior payment in full of all Senior Indebtedness of APUC. "**Senior Indebtedness**" of APUC is defined in the Series 3 Trust Indenture as all indebtedness of APUC, other than the APUC Debentures and any other debentures issued under the Series 3Trust Debenture, (whether outstanding as at the date of the Series 3 Trust Indenture or thereafter created, incurred, assumed or guaranteed), and including, for greater certainty, claims of trade

creditors of APUC, which by the terms of the instrument creating or evidencing the indebtedness, is not expressed to be *pari passu* with, or subordinate in right of payment to, APUC Debentures.

The Series 3 Trust Indenture provides that in the event of any insolvency or bankruptcy proceedings, or any receivership, liquidation or reorganization in connection with or as a result of an insolvency or bankruptcy proceeding or other similar proceedings relative to APUC, or to its property or assets, or in the event of any proceedings for voluntary liquidation, dissolution or other winding up of APUC, whether or not involving insolvency or bankruptcy, or any marshalling of the assets and liabilities of APUC, all creditors under any Senior Indebtedness will receive payment in full before the holders of APUC Debentures will be entitled to receive any payment or distribution of any kind or character, whether in cash, property or securities, which may be payable or deliverable in any such event in respect of any APUC Debenture or any unpaid interest accrued thereon.

In addition to the foregoing, pursuant to the terms of the Series 3 Trust Indenture, neither the Debenture Trustee for, nor the holders of, APUC Debentures are entitled to demand or otherwise attempt to enforce in any manner, institute proceedings for the collection of, or institute any proceedings against APUC, including, without limitation, by way of any bankruptcy, insolvency or similar proceedings or any proceeding for the appointment of a receiver, liquidator, trustee or other similar official (it being understood and agreed that the Debenture Trustee and/or the holders of APUC Debentures are permitted to take any steps necessary to preserve the claims of the holders of APUC Debentures in any such proceeding and any steps necessary to prevent the extinguishment or other termination of a claim or potential claim as a result of the expiry of a limitation period), or receive any payment or benefit in any manner whatsoever on account of indebtedness represented by APUC Debentures other than as set forth in the Trust Indenture at any time when (i) an event of default (howsoever designated) has occurred and is continuing under the Senior Credit Facility, or (ii) an event of default (howsoever designated) has occurred under any other Senior Indebtedness and is continuing and, in each case, notice of such event of default has been given by or on behalf of the lender or lenders party to such Senior Indebtedness to APUC or an affiliate thereof that is the borrower pursuant to such Senior Indebtedness (the "**Senior Indebtedness Postponement Provisions**").

The APUC Debentures are also subordinate to claims of creditors of APUC.

(vi) Put Right upon a Change of Control

Upon the occurrence of a change of control of APUC involving the acquisition of voting control or direction over 66 2/3% or more of the outstanding Common Shares by any person or group of persons acting jointly or in concert (a "**Change of Control**"), each holder of APUC Debentures may require APUC to purchase, on the date which is 30 days following the giving of notice of the Change of Control as set out below (the "**Put Date**"), the whole or any part of such holder's APUC Debentures at a price equal to 101% of the principal amount thereof (the " **Put Price**") plus accrued and unpaid interest to the Put Date.

If 90% or more in the aggregate principal amount of APUC Debentures outstanding on the date of the giving of notice of the Change of Control have been tendered for purchase on the Put Date, APUC will have the right to redeem all the remaining APUC Debentures on such date at the Put Price, together with accrued and unpaid interest to such date. Notice of such redemption must be given to the Debenture Trustee prior to the Put Date and as soon as possible

thereafter, by the Debenture Trustee to the holders of APUC Debentures not tendered for purchase. The principal on APUC Debentures will be payable in lawful money of Canada or, at the option of APUC and subject to applicable regulatory approval, by payment of Common Shares to satisfy, in whole or in part, its obligation to repay the principal amount of APUC Debentures.

The Series 3 Trust Indenture contains notification provisions to the effect that:

APUC will promptly give written notice to the Debenture Trustee of the occurrence of a Change of Control and the Debenture Trustee will thereafter give to the holders of APUC Debentures a notice of the Change of Control, the repayment right of the holders of APUC Debentures and the right of APUC to redeem un-tendered APUC Debentures under certain circumstances; and

(a) a holder of APUC Debentures, to exercise the right to require APUC to purchase its APUC Debentures, must deliver to the Debenture Trustee, not less than five business days prior to the Put Date, written notice of the holder's exercise of such right, together with a duly endorsed form of transfer.

(b) APUC will comply with the requirements of Canadian securities laws and regulations to the extent such laws and regulations are applicable in connection with the repurchase of APUC Debentures in the event of a Change of Control.

(vii) Modification

The rights of the holders of the APUC Debentures as well as any other series of debentures that may be issued under the Series 3 Trust Indenture may be modified in accordance with the terms of the Series 3 Trust Indenture. For that purpose, among others, the Trust Indenture contains certain provisions which will make binding on all holders of APUC Debentures resolutions passed at meetings of the holders of APUC Debentures by votes cast thereat by holders of not less than 66 2/3% of the principal amount of the then outstanding APUC Debentures present at the meeting or represented by proxy, or rendered by instruments in writing signed by the holders of not less than 66 2/3% of the principal amount of the then outstanding APUC Debentures. In certain cases, the modification will, instead of or in addition to, require assent by the holders of the required percentage of APUC Debentures of each particularly affected series. Under the Series 3 Trust Indenture, the Debenture Trustee has the right to make certain amendments to the Trust Indenture in its discretion, without the consent of the holders of APUC Debentures.

(viii) Events of Default

The Series 3 Trust Indenture provides that an event of default (" **Event of Default**") in respect of the APUC Debentures will occur if certain events described in the Series 3 Trust Indenture occur, including if any one or more of the following described events has occurred and is continuing with respect to the APUC Debentures: (i) failure for 15 days to pay interest on the APUC Debentures when due; (ii) failure to pay principal or premium, if any, on the APUC Debentures, whether at maturity, upon redemption, by declaration or otherwise; or (iii) certain events of bankruptcy, insolvency or reorganization of APUC under bankruptcy or insolvency laws. Subject to the Senior Indebtedness Postponement Provisions, if an Event of Default has occurred and is continuing, the Debenture Trustee may, in its discretion, and shall, upon the request of holders of not less than 25% in principal amount of the then outstanding APUC Debentures, declare the principal of (and premium, if any) and interest on all outstanding APUC Debentures to be immediately due and payable.

(ix) Offers for Debentures

The Series 3 Trust Indenture contains provisions to the effect that if an offer is made for APUC Debentures which is a take-over bid for APUC Debentures within the meaning of the Securities Act (Ontario) and not less than 90% of the APUC Debentures (other than APUC Debentures held at the date of the take-over bid by or on behalf of the offeror or associates or affiliates of the offeror) are taken up and paid for by the offeror, the offeror will be entitled to acquire the APUC Debentures held by holders of APUC Debentures who did not accept the offer on the terms offered by the offeror.

(x) Priority of Debt

The APUC Debentures are direct obligations of APUC and may not be secured by any mortgage, pledge, hypothec or other charge and are subordinated to other liabilities of APUC. The Trust Indenture does not restrict AUC from incurring additional indebtedness for borrowed money or from mortgaging, pledging or charging its assets to secure any indebtedness.

6.4 Employee Share Purchase Plan

In September 2011, APUC approved an employee share purchase plan (" **ESPP**"). Eligible employees may 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 match 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, 2011, a total of 7,176 shares had been issued under the ESPP. For the year ended December 31, 2011, APUC recorded $9 in compensation expense.

6.5 Directors Deferred Share Units

In June 2011, the Shareholders approved a Deferred Share Unit Plan. Under the plan, non-employee directors of APUC may elect annually to receive all or any portion of their compensation in deferred share units ("**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 expects to settle these instruments in cash, these DSUs will be accounted for as liability awards. The DSU liabilities will be marked-to-market at the end of each period based on the common share price at the end of the period.

As at December 31, 2011, no DSUs had been issued.

6.6 Performance Share Units

In October 2011, APUC issued 28,370 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 period and are converted to PSUs based on the market value of the shares on that date. None of these PSUs have voting rights. Any PSUs not vested at the end of a performance period will expire. The PSUs provide for settlement in cash or shares at the election of APUC. As APUC does not expect to settle these instruments in cash, these PSUs will be accounted for as equity awards. Compensation expense associated with PSUs is recognized rateably over the performance period based on APUC's estimated achievement of the established metrics. Compensation expense for awards with performance conditions will only be recognized for those awards for which it is probable that the performance conditions will be achieved and which are expected to vest. The compensation expense will be estimated based upon an assessment of the probability that the performance metrics will be achieved and anticipated vesting percentage.

6.7 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 of 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, 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. 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.

6.8 Stock Option Plan

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

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

The aggregate number of Common Shares that may be reserved for issuance under the Stock Option Plan must not exceed 10% of the number of Common Shares outstanding at the time the Options are granted. For greater clarity, the Stock Option Plan is "reloading" in the sense that, to the extent that Options expire or are terminated, cancelled or exercised, the Corporation may make a further grant of Options in replacement for such expired, terminated, cancelled or exercised Options, provided that the 10% maximum is not exceeded. No fractional Common Shares may be purchased or issued under the Stock Option Plan.

In addition, under the Stock Option Plan:

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

Under the Stock Option Plan, "**Market Price**" of the Common Shares is defined as the volume weighted average trading price of such Common Shares on the TSX (or, if such Common

Shares are not then listed and posted for trading on the TSX, on such stock exchange in Canada on which such Common Shares are listed and posted for trading as may be selected for such purpose by the Board) for the five (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 any:

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

  (ii) reduction of the Option 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 Persons that may permit an increase to the limit imposed on non-employee director participation set out in the Stock Option Plan;

(v) allowance 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.

7. MARKET FOR SECURITIES

7.1 Trading Price and Volume

(a) Common Shares

The Corporation's Common Shares are listed and posted for trading on the TSX under the symbol "AQN". The following table sets forth the high and low closing prices and the aggregate volume of trading of the Common Shares and trust units for the periods indicated (as quoted by the TSX).

2011	High ($)	Low ($)	Volume (000's)
January	5.03	4.73	6,167
February	5.13	4.81	5,018
March	5.42	4.85	5,654
April	5.63	4.98	9,523
May	5.87	5.23	7,487
June	5.86	5.44	5,755
July	5.99	5.59	2,563
August	5.83	4.90	6,599
September	5.85	5.40	4,362
October	5.88	5.47	5,872
November	6.13	5.52	9,249
December	6.59	5.96	22,740

(b) Series 1A Debentures

Series IA Debentures were listed and posted for trading on the TSX under the symbol “AQN.DB”. On the Redemption Date, the remaining Series 1A Debentures were redeemed. As a result, there are no Series 1A Debentures outstanding subsequent to the Redemption Date.

The following table sets forth the high and low closing prices and the aggregate volume of trading of the Series 1A Debentures for the periods indicated (as quoted by the TSX).

2011	High ($)	Low ($)	Volume (000’s)
January	122.79	118.00	58
February	125.50	119.62	16
March	130.70	120.89	29
April	137.52	121.00	191
May 1 -16, 2011	134.65	125.50	33

(c) Series 2A Debentures

Series 2A Debentures were listed and posted for trading on the TSX under the symbol “AQN.DB.A”. On the Series 2A Redemption Date, the remaining Series 2A Debentures were redeemed. As a result, there are no Series 2A Debentures outstanding subsequent to the Series 2A Redemption Date.

The following table sets forth the high and low closing prices and the aggregate volume of trading of the Series 2A Debentures for the periods indicated (as quoted by the TSX).

2011	High ($)	Low ($)	Volume (000’s)
January	107.00	106.00	1
February	107.50	106.31	2
March	109.00	106.70	2
April	107.50	107.00	4
May	107.50	106.00	4
June	108.74	106.76	8
July	108.00	106.50	5
August	107.00	102.00	7
September	106.50	104.00	9
October	106.00	103.00	8
November	107.80	104.51	6
December	110.00	104.25	48
January	108.60	102.50	11,000110
February 1 - 24	107.00	102.15	17,006176

(d) Series 3 Debentures

Series 3 Debentures are listed and posted for trading on the TSX under the symbol “AQN.DB.B”. The following table sets forth the high and low closing prices and the aggregate volume of trading of the Series 3 Debentures for the periods indicated (as quoted by the TSX).

2011	High ($)	Low ($)	Volume (000's)
January	121.00	115.33	44
February	125.00	118.05	19
March	130.67	120.00	25
April	135.00	121.02	15
May	139.58	127.11	26
June	140.00	131.53	21
July	144.00	135.01	5
August	140.00	120.00	53
September	139.10	131.00	15
October	140.00	133.00	24
November	145.00	133.40	15
December	155.34	143.17	34

7.2 Prior Sales

During the year ended December 31, 2010, 1,160,204 options were granted to senior executives of APUC which allow for the purchase of common shares at a price of $4.05. One-third of the options vest on each of January 1, 2011, 2012 and 2013.

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

- On March 22, 2011, 892,107 options were granted to senior executives of APUC which allow for the purchase of common shares at a price of $5.23;
- On June 21, 2011, 171,642 options were granted to a senior executive of APCo which allow for the purchase of common shares at a price of $5.64;
- On July 28, 2011, 90,909 options were granted to a senior executive of APUC which allow for the purchase of common shares at a price of $5.74; and
- On September 13, 2011, 172,242 options were granted to a senior executive of Liberty Utilities which allow for the purchase of common shares at a price of $5.68.

On March 14, 2012, 1,194,606 options were granted to senior executives of APUC and senior managers which allow for the purchase of common shares at a price of $6.22.

All options are issued at the market price of the underlying common share at the date of grant. In each case, one-third of the options vest on each of January 1, 2012, 2013 and 2014. Options may be exercised up to eight years following the date of grant.

During the year ended December 31, 2011, no options were exercised. As at December 31, 2011, APUC had 2,487,104 options issued and outstanding. As at December 31, 2011, 386,735 options are exercisable. No share options were exercised in 2011 or 2010.

	Number of shares	Weighted average exercise price	Weighted average remaining contractual term
Balance at January 1, 2011	1,160,204	$ 4.05	7.62
Granted	1,326,900	5.38	8.00
Balance at December 31, 2011	2,487,104	$ 4.76	6.96
Exercisable at December 31, 2011	386,735	$ 4.05	6.62

7.3 Escrowed Securities and Securities Subject to Contractual Restrictions on Transfer

The following securities of the Corporation are being held in escrow or subject to contractual restrictions on transfer as of the date of this AIF:

Description	Number of Securities held in escrow	Percentage of class
Subscription receipts	27,101,131(1)	100%
Common Shares	8,523,000(2)	5.8%

(1) Consists of the 12,000,000 subscription receipts issued pursuant to the Subscription Agreement (National Grid); 6,890,131 subscription receipts issued to Emera on July 5, 2011; and subscription receipts issued pursuant to the Subscription Agreement (Calpeco). These subscription receipts are being held by CIBC Mellon Trust Company as escrow agent. The Subscription Agreement (National Grid) will be released from escrow when the EnergyNorth and Granite State acquisitions are completed and the subscription receipts convert into APUC Common Shares (or if such acquisitions are terminated and the subscription receipts are cancelled). The 6,890,131 subscription receipts relate to an acquisition that the Corporation has determined not to proceed with, and such subscription receipts will be cancelled and released from escrow when a termination agreement relating to the subscription receipts is executed. The 8,211,000 subscription receipts will be released from escrow either (i) in two tranches, where 4,790,000 will be released when the Corporation completes the acquisition of Emera's interest in the California Utility and the subscription receipts convert into APUC Common Shares and 3,421,000 will be released following the completion of the California Utility's first rate case or (ii) if the acquisition of the California Utility is terminated.

(2) These shares were issued to Emera upon conversion of subscription receipts effective January 1, 2011. The shares are subject to restrictions on transfer until January 1, 2014, as set out in the Subscription Agreement dated April 22, 2009.

8. DIRECTORS AND OFFICERS

8.1 Name, Occupation and Security Holdings

The following table sets forth certain information with respect to the directors and executive officers of APUC, and information on their history with APCo. Unless otherwise indicated, the individuals have been in their principal occupations for more than five years.

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from	Number of Common Shares
CHRISTOPHER J. BALL Toronto, Ontario, Canada Age: 61	Mr. Ball is currently the Executive Vice President of Corpfinance International Limited, an investment banking boutique firm. From 1982 to 1988, Mr. Ball was Vice President at Standard Chartered Bank of Canada with responsibilities for the Canadian branch operation. Prior to that, Mr. Ball held various managerial positions with the Canadian Imperial Bank of Commerce. He is also a Director of the Independent Power Association of British Columbia.	Director of APUC since October 27, 2009. Trustee of APCo since October 22, 2002	24,200

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from	Number of Common Shares
KENNETH MOORE Toronto, Ontario, Canada Age: 53	Mr. Moore is currently the Managing Partner of NewPoint Capital Partners Inc., an investment banking firm. From 1993 to 1997, Mr. Moore was a senior partner at Crosbie & Co., another Toronto mid-market investment banking firm. Prior to investment banking, he was a Vice-President at Barclays Bank where he was responsible for a number of leveraged acquisitions and restructurings. Mr. Moore holds a Chartered Financial Analyst designation and has completed the Chartered Director program of the Directors College (McMaster University and the Conference Board) and has the certification of Chartered Director ("**Ch. Dir.**").	Director of APUC since October 27, 2009. Trustee of APCo since December 18, 1998	18,000
GEORGE L. STEEVES Aurora, Ontario, Canada Age: 62	Mr. Steeves is the Principal of True North Energy, an energy consulting firm. From January 2001 to April 2002, Mr. Steeves was a division manager of Earthtech Canada Inc. Prior to January 2001, he was the president of Cumming Cockburn Limited, an engineering firm, and has extensive financial expertise in acting as a Chairman, director and/or audit committee member of public and private companies, including APCo, Borealis Hydroelectric Holdings Inc. and KMS Power Income Fund. Mr. Steeves has completed the Chartered Director program of the Directors College (McMaster University and the Conference Board) and has the certification of Ch. Dir. He received a Bachelor and Masters of Engineering from Carleton University and holds the Professional Engineering designation in Ontario and British Columbia.	Director of APUC since October 27, 2009. Trustee of APCo since September 8, 1997	17,241[1]
CHRISTOPHER HUSKILSON Wellington, Nova Scotia, Canada Age: 54	Mr. Huskilson is currently the President and Chief Executive Officer of Emera Incorporated, a North American energy and services company. Since 1980, Mr. Huskilson has held a number of positions within Nova Scotia Power Inc, and is currently a director of Emera Incorporated, Nova Scotia Power Inc. and chairman of Bangor Hydro-Electric Company.	Director of APUC since October 27, 2009. Trustee of APCo since July 27, 2009	nil[2]
DAVID BRONICHESKI Oakville, Ontario, Canada Age: 52	Mr. Bronicheski is the Chief Financial Officer ("CFO") of APUC. He has held various senior management positions including Executive Vice President and CFO of a publicly traded income trust providing local telephone, cable television and internet service. He was also CFO for a large public hospital in Ontario. Mr. Bronicheski holds a Bachelor of Arts in economics (cum laude), a Bachelor of Commerce degree and an MBA. He is also a Chartered Accountant.	Officer of APUC since October 27, 2009. Officer of APCo since September 17 2007[3][4]	40,000[7][8][9]

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from	Number of Common Shares
CHRISTOPHER K. JARRATT[5] [6] Oakville, Ontario, Canada Age: 53	Mr. Jarratt is currently the Vice Chairman of APUC. Mr. Jarratt is a founder and principal of Algonquin Power Corporation Inc. ("APC"), a private independent power developer formed in 1988. Mr. Jarratt has completed the Chartered Director program of the Directors College (McMaster University and the Conference Board) and has the certification of Ch. Dir.. He holds a Professional Engineer designation and an Honours Bachelor of Science degree from the University of Guelph	Director of APUC since June 23, 2010.	407,444[7][8][9]
IAN E. ROBERTSON[5] [6] Oakville, Ontario, Canada Age: 52	Mr. Robertson is currently the President and Chief Executive Officer of APUC. Mr. Robertson is a founder and principal of APC. Mr. Robertson has completed the Chartered Director program of the Directors College (McMaster University and the Conference Board) and has the certification of Ch. Dir.. He received a Bachelor of Engineering from the University of Waterloo and holds the Professional Engineering designation along with a Master of Business Administration degree from York University and a Chartered Financial Analyst designation	Director of APUC since June 23, 2010.	423,546[7][8][9]
LINDA BEAIRSTO Ontario,Canada Age: 51	Ms. Beairsto has been general counsel for APUC since June 2011 and also holds the role of Corporate Secretary of APUC. Prior to her position with APUC, she was in-house legal counsel for a large Bay Street law firm and several multinational companies. Ms. Beairsto attended law at the University of New Brunswick and was called to the bar in Ontario in1990.	Officer of APUC since June 6, 2011	Nil[9] [10]

Notes:

(1) Mr. Steeves' directly owns 14,327 Common Shares and Mr. Steeves' spouse owns 2,914 Common Shares. Mr. Steeves exercises control and direction over the Common Shares owned by his spouse.
(2) Mr. Huskilson does not own any Common Shares.
(3) Mr. Bronicheski became an officer of APCo on September 17, 2007.
(4) Prior to becoming an officer of APCo in September 2007, Mr. Bronicheski was the CFO of Amtelecom Income Fund from July 2003 to July 2007.
(5) Messrs. Jarratt and Robertson, together with others, collectively own all of the issued and outstanding shares of APMI.
(6) As consideration for payment of APUC's acquisition of APMI's interest in the management agreement, Mr. Robertson and Mr. Jarratt following shareholder approval at the Meeting each received 295,045 Common Shares.
(7) Messrs. Jarratt, Robertson, and Bronicheski hold 436,224, 494,388, and 229,593 stock options respectively, granted on August 12, 2010. The stock options allow for the purchase of Common Shares at a price of $4.05. One-third of the stock options vests on each of January 1, 2011, 2012 and 2013. Stock options may be exercised up to eight years following the date of grant.
(8) Messrs. Jarratt, Robertson, and Bronicheski hold 335,423, 380,146, and 176,538 stock options respectively, granted on March 11, 2011. The stock options allow for the purchase of Common Shares at a price of $5.23. One-third of the stock options vests on each of January 1, 2012, 2013 and 2014. Stock options may be exercised up to eight years following the date of grant.
(9) Ms. Beairsto and Messrs. Jarratt, Robertson, and Bronicheski hold 85,000, 267,963, 350,413, and 162,917 stock options respectively, granted on March 14, 2012. The stock options allow for the purchase of Common Shares at a price of $6.22. One-third of the stock options vests on each of January 1, 2013, 2014, and 2015. Stock options may be exercised up to eight years following the date of grant.

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

Each director will serve as a director of APUC until the next annual meeting of shareholders or until his successor is elected in accordance with the by-laws of APUC (the "**By-Laws**").

As of March 30, 2011, approximately 870,990 Common Shares representing 0.59% of the issued and outstanding Common Shares are beneficially owned, directly or indirectly, by Senior Executives and approximately 930, 431 Common Shares representing 0.63% of the issued and outstanding Common Shares are beneficially owned, directly or indirectly, by the directors and executive officers of the Corporation.

8.2 Audit Committee

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

(a) Audit Committee Charter

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

(b) Relevant Education and Experience

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

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

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

Mr. Steeves received a Bachelor and Masters of Engineering from Carleton University. Mr. Steeves is the former president of Cumming Cockburn Limited and has extensive financial

experience in acting as a Chairman, director and/or audit committee member of public and private companies, including APCo, Borealis Hydroelectric Holdings Inc. and KMS Power Income Fund. Mr. Steeves has completed the Chartered Director program of the Directors College (McMaster University and the Conference Board) and has the certification of Ch. Dir. (Chartered Director). He received a Bachelor and Masters of Engineering from Carleton University and holds the Professional Engineering designation in Ontario and British Columbia.

(c) Pre-Approval Policies and Procedures

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

For the financial year ended December 31, 2011 and December 31, 2010, KPMG LLP charged the following fees to APUC:

Services	2011 Fees ($)	2010 Fees ($)
Audit Fees[1]	1,330,000	913,000
Audit-Related Fees[2]	278,000	110,000
Tax Fees[3]	907,850	885,000
All Other Fees	Nil	Nil

NOTES:

(1) For professional services rendered for audit or review or services in connection with statutory or regulatory filings or engagements. The 2011 fees include additional costs related to APCo private placement and APUC equity offering.
(2) For assurance and related services that are reasonably related to the performance of the audit or review of the Company's financial statements and not reported under Audit Fees, including accounting advice and French translation services. Fees related to financial statement audits of subsidiary companies and other regulatory filing requirements in 2010 of $265,000 were reclassified to Audit Fees for comparative purposes.
(3) For tax compliance, advice and planning services.

8.3 Corporate Governance and Compensation Committees

The directors have also established a Corporate Governance Committee (" **CGC**") comprised of three of the independent directors of APUC, Mr. Steeves (Chair), Mr. Huskilson and Mr. Moore. The CGC includes two members of management by invitation, Mr. Robertson and Mr. Bronicheski. The mandate of the CGC includes the director nominating and evaluation process. The CGC is responsible for reviewing APUC's corporate governance practices. The CGC will also consider and make recommendations to the board from time to time regarding the effectiveness of the Directors and whether an increase to the number of directors is warranted.

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

The CC shall exercise the responsibilities and duties set forth below, including but not limited to:

- Selecting and appointing the CEO of the Corporation;
- Approving executive compensation plan (including philosophy and guidelines);

- Recommending to the Board compensation arrangements for the CEO and reviewing and approving compensation arrangements for Designated Employees and Directors;
- Reviewing and approving management succession plans; and
- Approving the grant of stock options.

8.4 Bankruptcies

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

8.5 Potential Material Conflicts of Interest

Other than as set out below or disclosed elsewhere in this AIF and APUC's financial statements and management's discussion and analysis for the fiscal year ended December 31, 2011, APUC is not aware of any existing or potential material conflicts of interest between APUC or a subsidiary and any current director or officer of APUC or a subsidiary. Mr. Huskilson is a director of APUC but also the President and CEO of Emera, and Emera is a shareholder of APUC, is a co-owner of Calpeco with Liberty Utilities (West), has entered into agreement to acquire 12 million Common Shares through subscription receipts subject to certain trigger events, and is also in a strategic relationship with APUC. Mr. Huskilson does not vote in Board meetings on matters involving APUC's relationship with Emera nor on matters involving a potential conflict between APUC and Emera.

9. LEGAL PROCEEDINGS AND REGULATORY ACTIONS

9.1 Legal Proceedings

Except as disclosed elsewhere in this AIF, the only legal proceedings involving APUC or its subsidiaries that were material in 2011 are as follows:

(a) Trafalgar

As reported in previous public filings of APUC, 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 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. The Second Circuit Court of Appeals dismissed all the claims against APCo in the civil proceedings and remanded one issue to the District Court. The bankruptcy proceedings are continuing.

(b) Côte Ste-Catherine Water Lease Dues

On December 19, 1996, the Québec AG filed a suit in Québec Superior Court against a subsidiary of APUC claiming for amounts that the APUC subsidiary has been paying to The St. Lawrence Seaway Management Corporation ("**Seaway Management**") under its water lease with Seaway Management. The water lease contains a "hold harmless" clause which mitigates this claim. As such, the APUC subsidiary brought the Attorney General of Canada and Seaway Management (the "**Federal Authorities**") into the proceedings in an action in warranty. On March 27, 2009, the Superior Court dismissed the claim of the Québec AG and suspended the action in warranty following final judgment in this case.

The Québec AG subsequently appealed this decision and on October 21, 2011 the Québec Court of Appeal allowed the appeal and condemned the APUC subsidiary to pay approximately $5.4 million which includes the amount claimed with interest.

The APUC subsidiary believes it is held harmless in its water lease from this decision. The Federal Authorities have decided not to appeal this decision to the Supreme Court of Canada. APUC and Seaway Management are now required to go back to the Superior Court of Quebec which will determine the amount of money reimbursable by Seaway Management to APUC pursuant to the terms of the Water Lease. As a result, the probability of loss, if any, and its quantification cannot be estimated at this time but could range from $nil to $4.8 million. Accordingly, no accruals for amounts owed or recoverable in respect of the water lease dues already paid to Seaway Management have been recorded in the financial statements. Conversely, APCo accrued $1.0 million of water lease owed to Québec AG for 2008 to 2011, which years are subsequent to those covered by the Court Decision and might not be subject to the legal right of offset. Probable amounts recoverable from the Federal Authorities of $0.3 million were also recorded in 2011.

9.2 Regulatory Actions

Except as disclosed elsewhere in this AIF, during the financial year ended December 31, 2011, there have been:

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

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

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

10. INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as disclosed elsewhere in this AIF, and as disclosed in APUC's annual financial statements and management's discussion and analysis as at and for the periods ended

December 31, 2011, 2010, and 2009, management has no material interest, direct or indirect, in any transaction occurring within the three most recently completed financial years or during the current financial year that has materially affected or will materially affect APUC.

11. TRANSFER AGENTS AND REGISTRARS

The transfer agent and registrar for the Trust Units is CIBC Mellon Trust Company, at its offices in Toronto, Montréal, Vancouver, Calgary, Halifax and Winnipeg.

12. MATERIAL CONTRACTS

Except for certain contracts entered into in the ordinary course of business of APUC and its subsidiaries, the contracts described below are the only contracts entered into by APUC or its subsidiaries during 2011 (or prior to 2010 in the case of contracts that are still in effect) that are material to APUC. It is worthy of note that Transfer Agreements dated December 21, 2009 with each of the principals of APMI that transferred their interests in the Management Agreement (as discussed in the Management Information Circular dated June 1, 2010) were approved in 2010 by the Shareholders at the Meeting as well as the TSX. The previously disclosed material contracts with Management have all been terminated as they pertain to APUC. These are the Management Agreement, the Operations Supervisory Agreement, the Administration Agreement, the Governance Agreement and the Direct Operations Agreements, all as defined in the AIF of APUC dated March 31, 2011.

(a) **Cornwall Solar Acquisition**: On November 24, 2011 APCo entered into a share purchase agreement with EffiSolar, to acquire all of the issued and outstanding shares of Cornwall Solar Inc. On December 30, 2011 OPA approval was received and the transaction closed on January 4, 2012.

(b) **U.S. Wind Farm Portfolio**: Amended and Restated 51% Membership Interest Purchase and Sale Agreement (" **MIPA**") entered into as of December 30, 2011, as amended and restated as of March 8, 2012, by and among APFA (the "**Wind Farm Buyer**"), and Gamesa Energy USA, LLC, a Delaware limited liability company (the "**Wind Farm Seller**"). Termination of 49% MIPA by that certain letter to APFA c/o APUC dated March 8, 2012, sent by the Wind Farm Seller and as acknowledged and agreed to by the Wind Farm Buyer. 51% MIPA Guarantee dated as of March 8, 2012 made by APUC in favor of the Wind Farm Seller. 51% MIPA Guarantee dated as of March 8, 2012 made by Gamesa in favor of APFA. Indemnification Agreement entered into as of March 8, 2012, by and among the Wind Farm Seller and Gamesa, Wind Portfolio Sponsorco, LLC and APFA. Indemnification Agreement dated March 8, 2012, by and among the various parties to the transaction, including Gamesa and APFA.

(c) **Midwest Utility Transaction Documents:** An Asset Purchase Agreement entered into on May 12, 2011 between Atmos Energy Corporation, as Seller, and Liberty Midstates, as Buyer.

(d) **APCo debentures:** APCo Trust Indenture between APCo and BNY Trust Company of Canada dated July 25, 2011 providing for the issuance of senior unsecured debentures from time to time. A First Supplemental Trust Indenture between APCo and BNY Trust Company of Canada dated July 25, 2011 providing for the issuance of $135,000,000 5.50% senior unsecured debentures due July 25, 2018. The notes are interest only until maturity. The funds were used to repay the Airsource Senior Debt and to reduce outstanding indebtedness under the APCo Facility.

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

(f) **LU credit agreement:** Credit agreement dated January 18, 2012 between Liberty Utilities as Borrower and JP Morgan Chase Bank N.A. as Lender and Administrative Agent. The Lender has agreed to provide a three year, unsecured operating line of U.S. $80 million to Liberty Utilities to support the working capital and operating needs of Liberty Utilities and its subsidiaries.

(g) **Chaplin:** On February 28, 2012 APCo announced that it was awarded and had signed a 177 megawatt power purchase contract with SaskPower.

(i) **St Leon II:** On July 18, 2011 APUC executed of a 25-year PPA with Manitoba Hydro in respect of a 16.5MW expansion of APUC's existing St. Leon wind energy project located in the Province of Manitoba. On the same day the St. Leon II Energy LP executed a Turbine Supply Agreement and a Service and Maintenance Agreement with Vestas Canadian Wind Technology, Inc. for the procurement and operation of ten 1.65MW wind turbines.

(j) **National Grid Transaction Documents:** Two Stock Purchase Agreements each entered into on December 8, 2010 and amended and restated January 21, 2011 between National Grid, as Seller, and Liberty Energy, as Buyer. One agreement is for the purchase of all issued and outstanding shares of Granite State, and the other is for all the issued and outstanding shares of EnergyNorth. The interests of Buyer in the agreements have been transferred to Liberty Energy NH. The closings of the transactions are subject to certain conditions including state and federal regulatory approval, and are expected to occur in the second quarter of 2012.

(k) **Subscription Agreement (National Grid)**: Subscription agreement dated as of March 25, 2011 for the private placement of 12,000,000 subscription receipts from APUC to Emera at a price of $5.00 per subscription receipt. The proceeds of this subscription receipt transaction will be used to fund the National Grid acquisitions. See "*General Development of the Business – Significant Acquisitions – 2011 – New Hampshire Utility Acquisition*".

(l) **Subscription Agreement (First Wind):** Subscription agreement dated as of July 5, 2011 for the private placement of 6,890,131 subscription receipts from APUC to Emera at a price of $5.37 per subscription receipt. Payment for these subscription receipts was satisfied by delivery by Emera of a non-interest bearing promissory note in the amount of $37,000,000. Upon the satisfaction of conditions precedent to the closing of the investment in First Wind Holdings, LLC's ("**First Wind**") wind energy facilities portfolio in the North East United States (other than payment of the purchase price), including the receipt of all necessary regulatory approvals, the promissory note will become due and payable and the rights evidenced by the subscription receipts will be deemed to have been satisfied by the delivery of Common Shares from APUC on a one-for-one basis,

subject to customary anti-dilution adjustments. As APUC announced on January 27, 2012 that it will no longer proceed with the First Wind investment, these subscription receipts will be cancelled and will not convert into Common Shares of APUC.

13. INTERESTS OF EXPERTS

KPMG LLP is the external auditor of the Corporation and is independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Ontario.

14. ADDITIONAL INFORMATION

Additional information relating to APUC may be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of APUC's securities and securities authorized for issuance under equity compensation plans is contained in APUC's information circular for its most recent annual meeting. Additional financial information is provided in APUC's financial statements and management discussion and analysis for the year ended December 31, 2011.

SCHEDULE A

Renewable—Hydroelectric and Wind Facilities

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2012 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of PPA
Renewable Ontario Facilities					
Facility: Long Sault Rapids Facility (Hydroelectric) Owner: Algonquin Power (Long Sault) Partnership and N-R Power Partnership	18,000	Abitibi River near Cochrane, Ontario	**Electricity Purchaser:** OEFC **Rates:** $0.09634/kW-hr (average estimate)	111,600	2047
Facility: Hurdman Dam Facility (Hydroelectric) Owner: APFC	570	Mattawa River near Mattawa, Ontario	**Electricity Purchaser:** Ontario Power Authority Rates: $0.07334/kW-hr Paid on Hydroelectric Contract Incentive rate	3,150	2031
Facility: Burgess Dam Facility (Hydroelectric) Owner: APFC	140	Muskoka River near Bala, Ontario	**Electricity Purchaser:** Hydro One Inc Rates: Paid on Hourly Spot Market Price	0	month to month
Facility: Campbellford Facility (Hydroelectric) Owner: Campbellford LP	4,000	Trent River near Campbellford, Ontario	**Electricity Purchaser:** OEFC Rates: $0.04346/kW-hr (average estimate)	26,250	2019
Renewable Québec Facilities					
Facility: Saint-Alban Facility (Hydroelectric) Owner: SLI	8,200	Ste-Anne River near the Village of Saint-Alban, Québec	**Electricity Purchaser:** Hydro-Québec Rates: $0.07837/kW-hr (Jan – Nov) $0.08072/kW-hr (Dec)	37,650	2016
Facility: Glenford Facility (Hydroelectric) Owner: Glenford Partnership	4,950	Ste-Anne River near the Village of Ste-Christine d'Auvergne, Québec	**Electricity Purchaser:** Hydro-Québec Rates: $0.07837/kW-hr (Jan – Nov) $0.08072/kW-hr (Dec)	24,000	2020
Facility: Rawdon Facility (Hydroelectric) Owner: APFC	2,500	Ouareau River near the Village of Rawdon, Québec	**Electricity Purchaser:** Hydro-Québec Rates: $0.07837/kW-hr (Jan – Nov) $0.08072/kW-hr (Dec)	15,400	2014

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2012 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of PPA
Facility: Côte Ste-Catherine Facility (Hydroelectric) Owner: Mont-Laurier Partnership	11,120	St. Lawrence River near the Town of Ste.-Catherine, Québec	**Electricity Purchaser:** Hydro-Québec Rates: Phase I Energy $0.04911/kW-hr Phase II Energy $0.06703/kW-hr Capacity $164.10/kW * Phase III Energy $0.06979/kW-hr Capacity $172.06/kW* * calculated over the average kilowatt output over the period December to March	Phase 1: 15,500 Phase II: 35,100 Phase III: 34,750	Phase 1: 2021 Phase II: 2018 Phase III:2021
Facility: Ste-Raphaël Facility (Hydroelectric) Owner: APFC	3,500	Rivière de Sud near Québec City, Québec	**Electricity Purchaser:** Hydro-Québec Rates: $0.07837/kW-hr (Jan – Nov) $0.08072/kW-hr (Dec)	22,550	2014
Facility: Mont Laurier Facility (Hydroelectric) Owner: Mont-Laurier Partnership	2,725	Rivière-du-Lièvre in the Town of Mont Laurier, Québec	**Electricity Purchaser:** Hydro-Québec Rates: $0.05907/kW-hr	21,250	2027
Facility: Rivière-du-Loup Facility (Hydroelectric) Owner: APFC	2,600	Rivière-du-Loup near the Town of Rivière-du-Loup, Québec	**Electricity Purchaser:** Hydro-Québec Rates: $0.07837/kW-hr (Jan – Nov) $0.08072/kW-hr (Dec)	17,250	2015
Facility: Hydraska Facility (Hydroelectric) Owner: APT	2,250	Yamaska River near the Town of St.-Hyacinthe, Québec	**Electricity Purchaser:** Hydro-Québec Rates: Summer Energy $0.06591/kW-hr Winter Energy $0.12086/kW-hr	9,100	2014
Facility: Ste-Brigitte Facility (Hydroelectric) Owner: APFC	4,200	Nicolet River in the Municipality of Ste-Brigitte-des-Saults, Québec	**Electricity Purchaser:** Hydro-Québec Rates: $0.07837/kW-hr (Jan – Nov) $0.08072/kW-hr (Dec)	12,750	2014
Facility: Belleterre Facility (Hydroelectric) Owner: APFC	2,200	Winneway River in the Municipality of Laforce, Québec	**Electricity Purchaser:** Hydro-Québec Rates: Summer Energy: $0.06532/kW-hr Winter Energy: $0.12046/kW-hr Capacity: $161.45/kilowatt (over the average kilowatt output over the period December to March)	11,250	2013

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2012 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of PPA
Facility: Donnacona Facility (Hydroelectric) Owner: Donnacona Partnership	4,800	Jacques Cartier River near Donnacona, Québec	**Electricity Purchaser:** Hydro-Québec Rates: $0.07837/kW-hr (Jan – Nov) $0.08072/kW-hr (Dec)	20,550	2022
Facility: St. Raphaël de Bellechasse Facility (Arthurville) (Hydroelectric) Owner: APT	650	Riviere du Sud downstream from Ste-Raphaël	**Electricity Purchaser:** Hydro-Québec Rates: $0.07837/kW-hr (Jan – Nov) $0.08072/kW-hr (Dec)	0[4]	2013
Renewable New York Facilities					
Facility: Ogdensburg Facility (Hydroelectric) Owner: Trafalgar[2]	3,675	Oswegatchie River near Ogdensburg, New York	**Electricity Purchaser:** National Grid Rates: US$0.04296/kW-hr (est)[3]	11,100	2016
Facility: Forestport Facility (Hydroelectric) Owner: Trafalgar[2]	3,300	Black River near Boonville, New York	**Electricity Purchaser:** National Grid Rates: US$0.04265/kW-hr (est) [3]	11,500	2016
Facility: Herkimer Facility (Hydroelectric) Owner: Trafalgar[2]	1,680	West Canada Creek near Herkimer, New York	**Electricity Purchaser:** National Grid Rates: No target rate as the site is expected to be offline	0[4]	2016
Facility: Christine Falls Facility (Hydroelectric) Owner: Christine Falls Corporation[2]	850	Sacandaga River near Clifton, New York	**Electricity Purchaser:** National Grid Rates: US $0.04145/kW-hr (est) [3]	3,300	2028
Facility: Cranberry Lake (Hydroelectric) Owner: Trafalgar[2]	500	Oswegatchie River near Clifton, New York	**Electricity Purchaser:** National Grid Rates: US$0.04297/kW-hr (est) [3]	1,800	2016
Facility: Kayuta Lake Facility (Hydroelectric) Owner: Trafalgar[2]	400	Black River near Boonville, New York	**Electricity Purchaser:** National Grid Rates: US$0.00822/kW-hr (est)	1,800	2028
Facility: Adams Facility (Hydroelectric) Owner: Trafalgar [2]	350	Sandy Creek near Adams, New York	**Electricity Purchaser:** National Grid Rates: No target rate as the site is expected to be offline	0[4]	2028
Facility: Kings Falls Facility (Hydroelectric) Owner: Tug Hill Energy, Inc.[5]	1,750	Deer River near Copenhagen, New York	**Electricity Purchaser:** National Grid Rates: No estimate complete for 2012[6]	0[6]	2016

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2012 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of PPA
Facility: Otter Creek Facility (Hydroelectric) Owner: Tug Hill Energy, Inc.[5]	530	Otter Creek in Craig, New York	**Electricity Purchaser:** National Grid Rates: No estimate complete for 2012 [7]	0[6]	2016
Facility: Phoenix Facility (Hydroelectric) Owner: Oswego Hydro Partners L.P.[5]	3,500	Oswego River in Phoenix, New York	**Electricity Purchaser:** National Grid Rates: US$0.09205/kW-hr Flat Rate	11,250	2026
Facility: Beaver Falls Facility (Hydroelectric) Owner: Algonquin Power (Beaver Falls) LLC	2,500	Beaver River in Beaver Falls, New York	**Electricity Purchaser:** National Grid Rates: US$0.02852/kW-hr (est)	15,400	2019
Facility: Burt Dam Facility (Hydroelectric) Owner: Burt Dam Partnership	600	18 Mile Creek near Newfane, New York	**Electricity Purchaser:** National Grid Rates: No estimate complete for 2012 [6]	0[6]	2016
Facility: Hollow Dam Facility (Hydroelectric) Owner: Hollow Dam Partnership	900	Oswegatchie River near Gouverneur, New York	**Electricity Purchaser:** National Grid Rates: No estimate complete for 2012 [6]	0[6]	2016
New England Facilities					
Facility: Greggs Falls Facility (Hydroelectric) Owner: Greggs Falls Partnership	3,500	Piscataquog River near the Town of Goffstown, New Hampshire	**Electricity Purchaser:** Public Service Company of New Hampshire ("PSNH") Rates: US$0.05407/kW-hr (est) [5]	10,450	60 day written notice
Facility: Pembroke Facility (Hydroelectric) Owner: Pembroke Hydro Associates Limited Partnership	2,600	Suncook River near the Town of Pembroke, New Hampshire	**Electricity Purchaser:** PSNH Rates: US$0.05461/kW-hr (est) [5]	9,750	60 day written notice
Facility: Clement Facility (Hydroelectric) Owner: Clement Dam Hydroelectric LLC	2,400	Winnipisaukee River near the Town of Tilton, New Hampshire	**Electricity Purchaser:** PSNH Rates: US$0.05551/kW-hr (est) [5]	10,700	60 day written notice
Facility: Franklin Facility (Hydroelectric) Owner: Franklin Power LLC	River Bend 1,600 Steven's Mill 200	Winnipesaukee River near the Town of Franklin, New Hampshire	**Electricity Purchaser:** PSNH Rates: River Bend US$0.05291/kW-hr (est) [5] Steven's Mill US$0.05609/kW-hr (est) [5]	River Bend 6,800 Steven's Mill 950	60 day written notice – both sites

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2012 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of PPA
Facility: Lochmere Facility (Hydroelectric) Owner: HDI Partnership	1,200	Winnipesaukee River near Lochmere, New Hampshire	**Electricity Purchaser:** PSNH Rates: US$0.05560/kW-hr (est) [5]	4,150	60 day written notice
Facility: Lakeport Facility (Hydroelectric) Owner: Lakeport Corporation	600	Winnipesaukee River near Laconia, New Hampshire	**Electricity Purchaser:** PSNH Rates: US$0.05530/kW-hr (est) [5]	2,450	60 day written notice
Facility: Mine Falls Facility (Hydroelectric) Owner: Mine Falls Limited Partnership	3,000	Nashua River near the City of Nashua, New Hampshire	**Electricity Purchaser:** PSNH Rates: US $0.05483/kW-hr (est) [5]	11,400	60 day written notice
Facility: Great Falls Facility (Hydroelectric) Owner: Great Falls Partnership	10,950	Passaic River near the City of Paterson, New Jersey	**Electricity Purchaser:** Public Service Electric and Gas Company Rates: US $0.05470/kW-hr (est) [5]	23,350	60 day written notice
Facility: Moretown Facility (Hydroelectric) Owner: Moretown Partnership	1,200	Mad River near Moretown, Vermont	**Electricity Purchaser:** Vermont Power Exchange, Inc. Rates: $0.10780/kW-hr (average estimate)	0[4]	2018
Renewable—Western Canada Facility					
Facility: Dickson Dam Facility (Hydroelectric) **Owner:** APOT	15,000	Innisfail, Alberta	**Electricity Purchaser:** AESO Rates: Market Rates Energy: $0.0620/kW-hr (estimate)	65,000	NA
Renewable—Maritime Facilities					
Facility: Tinker Facility (Hydroelectric) Owner: APT	33,500	Perth-Andover, New Brunswick	**Electricity Purchaser:** AES Town of Perth-Andover **Rates:** AES ~ U.S. $0.046/kWhr Town of Perth Andover: ~ CDN $.085/kWhr (including transmission charges)	120,000	Perth-Andover Contract through 2021 AES contract through 2013
Facility: Caribou Facility (Hydroelectric) **Owner:** Maine Gen Co.	900	Caribou, Maine	**Electricity Purchaser:** AES **Rates:** Energy – ~U.S. $0.046/kWhr	5,300	n/a
Facility: Squa Pan Facility (Hydroelectric) Owner: Maine Gen Co.	1,400	Squa Pan Lake, near Caribou Maine	**Electricity Purchaser:** AES **Rates:** Energy – ~U.S. $0.046/kWhr	850	n/a

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2012 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of PPA
Facility: Rattle Brook Facility (Hydroelectric) Owner: Rattlebrook Partnership	4,000	Rattle Brook near Jackson's Arm, Newfoundland	**Electricity Purchaser:** Newfoundland and Labrador Hydro Rates: Summer $0.07148/kW-hr Winter $0.09693/kW-hr	15,950	2024
Renewable—Solar Facility					
Facility: Cornwall Solar (Solar)	10,000	Cornwall, Ontario	**Electricity Purchaser:** (Under Development - OPA)	13,400	n/a
Renewable—Wind Facilities					
Facility: Chaplin Wind (Wind)	177,000	Chaplin, Saskatchewan	**Electricity Purchaser:** (Under Development - SaskPower)	247,000	n/a
Facility: St. Leon Facility (Wind) Owner: St. Leon LP	104,000	St. Leon, Manitoba	**Electricity Purchaser:** Manitoba Hydro	372,000	2025 + one 5 year extension
Facility: Amherst Island (Wind)	75,000	Stella, Ontario	**Electricity Purchaser:** (Under Development - OPA)	247,000	n/a
Facility: Red Lily (Wind) Owner: Concord	26,400	Saskatchewan	**Electricity Purchaser:** SaskPower	88,000	2036
Facility: Morse (Wind)	25,000	Morse, Saskatchewan	**Electricity Purchaser:** (Under Development - SaskPower)	93,000	n/a
Facility: Saint-Damase (Wind)	24,000	Saint-Damase, Québec	**Electricity Purchaser:** (Under Development – Hydro-Quebec)	86,000	n/a
Facility: Val-Éo (Wind)	24,000	Saint-Gédéon, Québec	**Electricity Purchaser:** (Under Development – Hydro-Quebec)	66,000	n/a
Facility: St. Leon II Facility (Wind)	16,500	St. Leon, Manitoba	**Electricity Purchaser:** Manitoba Hydro	58,000	2037

Notes:

(1) 2012 PPA rates have been rounded to four decimals and are not representative of long term power purchase rates under the applicable PPAs. Long-term rates under different agreements will be both higher and lower than current rates. Seasonal periods and daily periods vary from project to project.

(2) APC provides Trafalgar with certain operational services in respect of the Trafalgar Facilities.

(3) These rates reflect the estimated Avoided Costs of National Grid.

(4) Scheduled to be offline for repairs in 2012. No decision has been made as to the timing of repairing these Facilities.

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

(6) This facility no longer fits APUC's preferred asset profile and is no longer considered strategic to APUC. As a result, APUC's interest in these facilities is expected to be sold in 2012.

SCHEDULE B

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

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2012 Power Purchase Rates	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of PPA	Year of Expiry of Lease
Thermal - Biomass Facility						
Facility: Valley Power Facility (Biomass) Owner: Valley Power L.P.	12,000	Drayton Valley, Alberta	**Electricity Purchaser:** TransAlta Utilities Corporation Rates: Energy: $0.0709/kW-hr	0[(1)]	2014	Owned
Thermal—Cogeneration Facilities						
Facility: Sanger Facility (Cogeneration) Owner: Algonquin Power Sanger LLC	56,000	Sanger, California	**Electricity Purchaser:** PG&E **Rates:** US$ 0. 045/ kW-hr (estimated average)* * subject to gas price indexing Capacity – Approximately $298,000 January-April &November-December Approximately $1,093,000 May-October	98,000	2021	Owned
Facility: Windsor Locks Facility (Cogeneration) Owner: Algonquin Power Windsor Locks LLC	56,000	Windsor Locks, Connecticut	**Electricity Purchaser:** ISO New England Ahlstrom **Rates:** ISO New England-Market Rates , included hourly energy, forward capacity and forward reserve payments Mill/NGC - US$0. 049/kW-hr* Capacity $203,000** Steam - DNM/NGC - US$7.26/1000lbs* Capacity $127,000 * Estimated average rate, includes variable component based on natural gas prices. **Estimated average monthly rate, charges are CPI indexed. Capacity Market and Spot Market – market prices	176,000 87,000	Merchant 2018	2018
Facility: Brampton Cogeneration Inc. (Cogeneration) Owner: APOT	N/A	Brampton, Ontario	**Electricity Purchaser:** N/A Rates: Steam - Normapac $8.45/1000lbs* Capacity $103,600** * Estimated average rate, includes variable component based on natural gas prices. **Estimated average monthly rate, charges are partially CPI indexed.	604 million lbs of steam	2024	N/A
Facility: EFW Facility (Energy from Waste) Owner: Algonquin Power Energy from Waste Inc.	10,100	Brampton, Ontario	**Electricity Purchaser:** OEFC Rates: $0.060/kW-hr (average estimated rate) Tipping - Peel – $91/tonne up to 127,900 tonnes, $66 tonnes thereafter Waste rates subject to monthly CPI indexing	7,450	2012	Owned

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2012 Power Purchase Rates	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of PPA	Year of Expiry of Lease
Thermal – Diesel Facilities						
Facility: Tinker Facility (Diesel) Owner: Tinker Gen Co.	1,000	Perth-Andover, New Brunswick	**Electricity Purchaser:** Not Under Contract **Rates:** Capacity only	0	NA	Owned
Facility: Caribou Facility (Diesel) Owner: Maine Gen Co.	7,000	Caribou, Maine	**Electricity Purchaser:** AES **Rates:** Capacity only	0	NA	Owned
Facility: Flo's Inn Facility (Diesel) Owner: Maine Gen Co.	4,000	Caribou, Maine	**Electricity Purchaser:** Not Under Contract **Rates:** **n/a**	0(2)	NA	Owned

Notes:

(1) This facility no longer fits APUC's preferred asset profile and is no longer considered strategic to APUC. As a result, APUC's interest in these facilities is expected to be sold in 2012.

(2) Available to provide capacity only. The thermal facilities located in Northern Maine and New Brunswick are not considered strategic to APUC. As a result APUC is taking steps to shutdown these facilities.

SCHEDULE C

Wastewater and Water Distribution Facilities

Utility	Owner	Location	Type of Utility	December 31, 2011 Connections	Rates
Black Mountain	Black Mountain Sewer Corporation	Carefree, Arizona	Wastewater	2,276	Residential US $65.24 (standard monthly rate)
Gold Canyon	Gold Canyon Sewer Company	Gold Canyon Arizona	Wastewater	7,423	Residential US $52.40 (standard monthly rate)
Bella Vista	Bella Vista Water Co., Inc.	Sierra Vista, Arizona	Water Distribution	9,012	Residential US $15.00 (Average monthly rate)
Tall Timbers	Tall Timbers Utility Company, Inc.	Tyler, Texas	Wastewater	2,185	Residential US $54.93 (standard monthly rate)
Woodmark	Woodmark Utilities, Inc.	Tyler, Texas	Wastewater	1,731	Residential US $47.76 (standard monthly rate)
Litchfield Park	Litchfield Park Service Company	Litchfield, Park, Arizona	Wastewater Water Distribution	18,891 16,564	Residential US $56.54 Commercial US $95.60 US $39.58 (Average residential rate)
Fox River	AWRI	Sheridan, Illinois	Wastewater Water Distribution	219 220	US $240.08 US $141.61
Timber Creek	AWRM	DeSoto, Missouri	Wastewater Water Distribution	20 25	US $16.00 min & $17.24/1000 gal. US $8.96 min. & US $5.96/1000 gal
Holiday Hills	AWRM	Branson, Missouri	Water Distribution	484	US $8.96 min. & US $5.96/1000 gal
Ozark Mountain	AWRM	Kimberling City, Missouri	Wastewater Water Distribution	241 256	US $16.00 min & $17.24/1000 gal. US $8.96 min. & $5.96/1000 gal
Holly Lake Ranch	AWRT	Hawkins, Texas	Wastewater Water Distribution	152 1,725	US $128.53 min & US $3.65/1000 gal. US $30.20 min. & $2.89/1000 gal
Big Eddy	AWRT	Flint, Texas	Wastewater Water Distribution	411 668	US $128.53 min & US $3.65/1000 gal. US $30.20 min. & $2.89/1000 gal
Piney Shores	AWRT	Conroe, Texas	Wastewater Water Distribution	269 273	US $128.53 min & US $3.65/1000 gal. US $39.81 min. & $1.30/1000 gal
Hill Country	AWRT	New Braunfels, Texas	Wastewater Water Distribution	379 225	US $128.53 min & US $3.65/1000 gal. US $39.81 min. & $1.30/1000 gal

Utility	Owner	Location	Type of Utility	December 31, 2011 Connections	Rates
Rio Rico	Rio Rico Utilities Inc.	Rio Rico, Arizona	Wastewater Water Distribution	2,207 6,429	US $45.88 (residential rates) US $10.98 min. & 0-3,000 gal – US $1.59/1,000 gal 3,001-9,000 gal – US $2.92/1,000 gal >9,000 gal – US $3.64/1,000 gal
Northern Sunrise	Northern Sunrise Water Company Inc.	Sierra Vista, Arizona	Water Distribution	352	US $15.00 min / Per 1000 / 0-4,000gal $1.45/ 4,000-10,000 gal $2.21 / >10,000 gal $2.72
Southern Sunrise	Southern Sunrise Water Company Inc.	Sierra Vista, Arizona	Water Distribution	866	US $15.00 min / Per 1000 / 0-4,000gal $1.45/ 4,000-10,000 gal $2.21 / >10,000 gal $2.72
Entrada Del Oro (1)	Entrada Del Oro Sewer Company	Gold Canyon , Arizona	Wastewater	337	US $70.00 (standard monthly rate)
Seaside Resort	AWRT	Galveston, Texas	Water Distribution Wastewater	156 156	US $166.68 US $165.45
Noel	AWRM	Noel, Missouri	Water Distribution	612	US $7.76 Consumption $1.80 per 1000 gallons
KMB	AWRM	Jefferson, Franklin and Cape Girardeau counties in Missouri	Wastewater Water Distribution	190 546	$27.60 Varies – Fixed Average US $17.33 Consumption Average US $3.57 per 1000 gal;
Total connections				**75,500**	

Notes:

(1) Liberty Water Co. currently holds a beneficial interest in the shares of the company pending regulatory approval of its acquisition.

SCHEDULE D

Electrical Distribution Facilities

Utility	Owner[1]	Location	Type of Utility	December 31, 2011 Connections	Rates
Calpeco	California Pacific Electric Company, LLC	Lake Tahoe, California	Electricity Distribution	47,000	Residential Rates – Monthly Charge $6.62 plus $0.10864/kwh for baseline usage; $0.13696 for excess usage. Commercial (Small) – Monthly Charge $12.22 plus $0.12882/kwh for baseline usage. Commercial - (Medium) – Monthly Charge $108.94 plus average rate of $0.09969/kwh for baseline usage. Commercial - (Large) – Monthly Charge $223.98 plus an average rate of $0.069376/kwh for baseline usage.

SCHEDULE E

ALGONQUIN POWER & UTILITIES CORP.

MANDATE OF THE AUDIT COMMITTEE

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

1. PURPOSE

1.1 The Committee's purpose is to:

(a) assist the Board's oversight of:

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

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

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

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

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

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

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

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

2. COMMITTEE MEMBERSHIP

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

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

(a) be a director of the Corporation;

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

(c) be an unrelated director for the purposes of the Toronto Stock Exchange (the "**TSX**") Corporate Governance Policy; and

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

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

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

3. COMMITTEE MEETINGS

3.1 Time and Place of Meetings – The time and place of the meetings of the Committee and the calling of meetings and the procedure in all things at such meetings shall be determined by the Committee; provided, however, that the Committee shall meet at least quarterly, a majority of the members of the Committee shall constitute a quorum and the Committee shall maintain minutes or other records of its meetings and activities.

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

(a) representatives of Management;

(b) the external auditor; and

(c) the internal audit personnel.

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

4. **COMMITTEE AUTHORITY AND RESOURCES**

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

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

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

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

5. REMUNERATION OF COMMITTEE MEMBERS

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

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

6. DUTIES AND RESPONSIBILITIES OF THE COMMITTEE

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

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

(a) Financial and Related Information

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

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

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

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

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

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

(C) other material written communications between the external auditor and Management, such as any management letter,

schedule of unadjusted differences, listing of adjustments and reclassifications not recorded, management representation letter, report on observations and recommendations on internal controls, engagement letter and independence letter;

(D) major issues regarding financial statement presentations;

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

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

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

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

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

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

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

(b) External Auditor

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

removed from office, and the compensation of the external auditor. The Committee shall require the external auditor to confirm in an engagement letter to the Committee each year that the external auditor is accountable to the Board and the Committee as representatives of shareholders and that it will report directly to the Committee.

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

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

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

(B) In accordance with applicable laws and regulations, the Committee shall pre–approve any non–audit services (including, without limitation, fees therefore) provided to the Corporation or its subsidiaries by the external auditor or any auditor of any such subsidiary and shall consider whether these services are compatible with the external auditor's independence, including, without limitation, the nature and scope of the specific non–audit services to be performed and whether the audit process would require the external auditor to review any advice rendered by the external auditor in connection with the provision of non audit services. The Chair may approve additional non audit services that arise between Committee meetings, provided that the Chair reports any such approvals to the Committee at the next scheduled meeting.

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

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

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

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

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

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

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

(vii) Regulatory Matters – The Committee shall discuss with the external auditor the matters required to be discussed by CAS 260 of the CICA Handbook – Assurance relating to the conduct of the audit.

(c) Internal Audit Function – Controls

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

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

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

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

(d) Risk Assessment and Risk Management

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

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

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

(e) Legal Compliance

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

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

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

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

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

(g) Related Party Transactions – The Committee shall review and approve any transaction between the Corporation and a related party and any transaction involving the Corporation and another party in which the parties' relationship could enable the negotiation of terms on other than an independent, arms' length basis.

(h) Review of the Management's Certifications and Reports – The Committee shall review and discuss with Management all certifications of financial information,

management reports on internal controls and all other management certifications and reports relating to the Corporation's financial position or operations required to be filed or released under applicable laws and regulations prior to the filing or release of such certifications or reports.

(i) Liaison – The Committee shall review and ensure that appropriate liaison and co–operation exist between the external auditor and internal audit personnel and provide a direct channel of communication between external and internal auditors and the Committee.

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

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

7. **REPORTING TO THE BOARD**

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

8. **EVALUATION OF COMMITTEE PERFORMANCE**

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

8.2 Amendments to Charter

(a) Review by Committee – On at least an annual basis, the Committee shall review and discuss the adequacy of this Charter and if applicable, recommend any proposed changes to the Board.

(b) Review by Board – The Board will review and reassess the adequacy of the Charter on an annual basis and at such other times, as it considers appropriate.

9. **LEGISLATIVE AND REGULATORY CHANGES**

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

10. **CURRENCY OF CHARTER**

10.1 Currency of Charter – This Charter was approved by the Board of Directors of Algonquin Power & Utilities Corp. effective March 31, 2010.

SCHEDULE F

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.

SCHEDULE G

GLOSSARY OF TERMS

In this Annual Information Form, the following terms have the meanings set forth below, unless otherwise indicated.

"**3793257**" means 3793257 Canada Inc., a corporation incorporated under the CBCA. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

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

"**ADEQ**" means the Arizona Department of Environmental Quality. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Utilities: Water and Wastewater".*

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

"**AESO**" means the Alberta Electric System Operator. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric".*

"**Agreement**" has the meaning ascribed thereto under " *General Development of the Business—Recent Developments – 2012 – Corporate – Business Associations with APMI and Senior Executives"*.

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

"**AirSource Senior Debt**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History – Fiscal 2011".*

"Algonquin" or the **"Fund"** means Algonquin Power Income Fund. See *"General Development of the Business – General – The Unit Exchange".*

"**Algonquin Holdco**" means Algonquin Power Fund (America) Holdco Inc., a Delaware corporation. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

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

"**APC**" means Algonquin Power Corporation Inc. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric".*

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

"**APCo Facility**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History – Fiscal 2011".*

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

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

"**APFC**" means Algonquin Power Fund (Canada) Inc. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**APMI**" means Algonquin Power Management Inc. See *"General Development of the Business – Three Year History – Fiscal 2009".*

"**APOT**" means Algonquin Power Operating Trust. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**APT**" means Algonquin Power Trust. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**APUC**" or the **"Corporation"** means Algonquin Power & Utilities Corp including, for reporting purposes only, the direct or indirect subsidiaries of APUC and partnership interests held by APUC and its subsidiaries. See *"Corporate Structure – Name, Address and Incorporation"*.

"**APUC Businesses**" means the two businesses through which APUC primarily conducts its operations: independent power generation and utilities (water, gas and electric). See *"General Development of the Business – General—Business Strategy".*

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

"**Audit Committee**" means APUC's audit committee. See *"Directors and Officers – Audit Committee – Audit Committee Charter".*

"**Avoided Costs**" means costs a utility does not incur to add new generating capacity to the system by purchasing electricity from an independent or parallel generator. See *"Description of the Business – General Description of the Regulatory Regimes in which the Business Operates – Power Generation Regulatory Regimes".*

"AWPH" means American Wind Portfolio Holdings LLC. See *"General Development of the Business – Recent Developments – 2012".*

"**BCI**" means Brampton Cogeneration Inc.

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

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

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

"**By-Laws"** means the by-laws of APUC.

"**California Utility**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History – Fiscal 2010"*.

"**Calpeco**" means California Pacific Electric Company, LLC, a California limited liability company. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

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

"**Campbellford LP**" means Algonquin Power (Campbellford) Limited Partnership. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Canadian ERs**" means the updated Final Essential Requirements for Mandatory Reporting for use in Canadian Partner jurisdictions. See *"Risk Factors – Operational Risk Management – Specific Environmental Risks"*.

"**Caribou Facility**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History – Fiscal 2010"*.

"**CBCA**" means the *Canada Business Corporations Act*.

"**CC**" means Compensation Committee. See *"Directors and Officers – Corporate Governance and Compensation Committees"*.

"**CDP**" means the Carbon Disclosure Project. See *"Risk Factors – Operational Risk Management – Specific Environmental Risks"*.

"**CGC**" means Corporate Governance Committee. See *"Directors and Officers – Corporate Governance and Compensation Committees"*.

"**Change of Control**" means the acquisition of voting control or direction over 66 2/3% or more of the outstanding Common Shares by any person or group of persons acting jointly or in concert. See *"Description of Capital Structure – Convertible Debentures – Series 3 Debentures"*.

"**Chapais**" means Chapais Energie, Société en Commandité. See *"Corporate Structure – Intercorporate Relationships – Other Interests in Energy Related Developments"*.

"**Clarica**" means The Clarica Life Insurance Company. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric"*.

"**CL&P**" means the Connecticut Light and Power Company. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Thermal – Cogeneration"*.

"**Cochrane**" means Cochrane Power Corporation. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Thermal – Cogeneration"*.

"**COD**" means commercial operation dates. See *"General Development of the Business – Recent Developments – 2012"*.

"**Common Shares**" means a new class of common shares created pursuant to a certificate and articles of arrangement dated October 27, 2009. See *"Corporate Structure – Name, Address and Incorporation"* .

"**Corporation**" means APUC.

"**Corporation St-Laurent**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Court Street**" means Court Street Investments, Inc., a Massachusetts corporation. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Co-Owners**" means Algonquin Power (Long Sault) Partnership and N-R Power Partnership as co-owners of the Long Sault Rapids Facility. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric"*.

"**CPUV**" means California Pacific Utilities Ventures, LLC, a California limited liability company. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Current Market Price**" is defined in the Series 3 Trust Indenture to mean the weighted average trading price of the Common Shares on the TSX for the 20 consecutive trading days ending on the fifth trading day preceding the date of the applicable event. See *"Description of Capital Structure – Convertible Debentures – Series 3 Debentures"*.

"**DEP**" means the US Department of Energy.

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

"**ECAC**" means the Energy Cost Adjustment Clause. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Liberty Utilities: Electrical Distribution"*.

"**EffiSolar**" means EffiSolar Energy Corporation. See *"General Development of the Business – Significant Acquisitions and Investments – 2011 – Cornwall Solar"*.

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

"**Electricity Act**" means the *Electricity Act (New Brunswick)*. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric"*.

"**EnergyNorth**" means EnergyNorth Natural Gas Inc. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"* .

"**Entrada**" means Entrada Del Oro Sewer Company, Inc. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Éoliennes**" means Corporation D'Investissements Éoliennes Algonquin Power. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**EPA**" means the Environmental Protection Agency.

"**EPA Rule**" means the final Mandatory Greenhouse Gas Reporting Rule. See *"Risk Factors – Operational Risk Management – Specific Environmental Risks"*.

"**ERs**" means the Final Essential Requirements for Mandatory Reporting. See *"Risk Factors – Operational Risk Management – Specific Environmental Risks"*.

"**ESA**" means energy services agreement. See *"General Development of the Business – Three Year History – Fiscal 2011"*.

"**ESPP**" means employee share purchase plan.

"**EUA**" means the *Electric Utilities Act (Alberta)*. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric"*.

"**Event of Default**" has the meaning ascribed thereto under *"Description of Capital Structure – Convertible Debentures – Series 3 Debentures"*.

"**Federal Authorities**" means, together, the Attorney General of Canada and Seaway Management. See *"Legal Proceedings and Regulatory Actions – Legal Proceedings—Côte Ste-Catherine Water Lease Dues"*.

"**FERC**" means the United States Federal Energy Regulatory Commission. See *"Description of the Business – General Description of the Regulatory Regimes in which the Business Operates – Power Generation Regulatory Regimes"*.

"**First Wind**" means First Wind Holdings, LLC. See *"Material Contracts"*.

"**FIT**" has the meaning ascribed thereto under *"General Development of the Business – Significant Acquisitions and Investments – 2011 – Cornwall Solar"*.

"**Fleur de Lis LP**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**FPA**" means the U.S. Federal Power Act.

"**Gamesa**" means Gamesa Corporación Tecnológica, S.A. See *"General Development of the Business – Recent Developments – 2012"*.

"**gpd**" means gallons per day. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Utilities: Water and Wastewater"*.

"**Granite State**" means Granite State Electric Company. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**Green Power**" means electricity generated from renewable energy sources that do not contribute to greenhouse gas emissions. See *"Description of the Business – General Description of the Regulatory Regimes in which the Business Operates – Power Generation Regulatory Regimes".*

"**HOEP**" means Hourly Ontario Energy Price.

"**ICC**" means Illinois Commerce Commission.

"**ISO-NE**" means Independent System Operator New England. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Thermal – Cogeneration".*

"**ITC**" means investment tax credit.

"**IUB**" means Iowa Utilities Board.

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

"**Kirkland**" means Kirkland Lake Power Corp. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Thermal – Cogeneration".*

"**Liberty Energy**" means Liberty Energy Utilities Co. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**Liberty Energy (NH)**" means Liberty Energy Utilities (New Hampshire) Corp., a Delaware corporation registered in New Hampshire. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**Liberty Facility**" has the meaning ascribed thereto under *"General Development of the Business – Recent Developments—2012".*

"**Liberty Midstates**" means Liberty Energy (Midstates) Corp., a Missouri corporation. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**Liberty Utilities**" means Liberty Utilities Company. See *"Corporate Structure – Name, Address and Incorporation"* .

"**Liberty Water**" means Liberty Water Co., a Delaware company. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"* .

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

"**LSR Royalty Interest**" means a royalty in the form of cash flows generated by the Long Sault Rapids Facility. See *"Corporate Structure – Intercorporate Relationships – Other Interests in Energy Related Developments"*.

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

"**LU GP1**" means Liberty Utilities Finance GP 1, a special purpose financing company and a Delaware general partnership. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**LU GP2**" means Liberty Utilities Finance GP 2, a special purpose financing company and a Delaware general partnership. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

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

"**Meeting**" means the annual general meeting held on June 23, 2010.

"**Midwest Gas Utilities**" means certain natural gas distribution utility assets located in Missouri, Iowa, and Illinois. See *"General Development of the Business – Significant Acquisitions and Investments – 2011 – Midwest Gas Utility Acquisition"*.

"**Midwest Purchase Agreements**" means the share purchase agreements by and between Atmos and Liberty Midstates entered into on May 12, 2011. See *"General Development of the Business – Significant Acquisitions and Investments – 2011 – Midwest Gas Utility Acquisition"* .

"**MIPA**" means Membership Interest Purchase and Sale Agreement. See *"Material Contracts"*.

"**Ministry**" means the Minister of Energy and Infrastructure. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Development".*

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

"**MPS**" means Maine Public Service Company.

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

"**MW**" means megawatt.

"**National Grid**" means National Grid USA. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"* .

"**NB Power**" means New Brunswick Power Corporation.

"**NBSO**" means New Brunswick System Operator. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric".*

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

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

"**Northland**" means Northland Power Inc. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Thermal – Cogeneration"*.

"**NTP**" means Notice to Proceed. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Development"*.

"**OATT**" means open access transmission tariff. See *"Description of the Business – General Description of the Regulatory Regimes in which the Business Operates – Power Generation Regulatory Regimes"*.

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

"OEFC" means Ontario Electric Financial Corporation.

"**Offering**" means a public offering completed by APUC on October 27, 2011 of 15,100,000 common shares at a price of $5.65 per share, for gross proceeds of approximately $85.3 million. See *"General Development of the Business – Three Year History – Fiscal 2011"*.

"**Off-peak**" means the hours other than On-peak hours. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric"*.

"**On-peak**" means between 7:00 a.m. and 11:00 p.m., local time, Monday to Friday, inclusive, but excluding public holidays. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric"*.

"**Parties**" has the meaning ascribed thereto under "*General Development of the Business—Recent Developments – 2012 – Corporate – Business Associations with APMI and Senior Executives"*.

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

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

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

"**Power Pool**" means the Power Pool of Alberta. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric"*.

"**Power Sales Contracts**" has the meaning ascribed thereto under *"General Development of the Business – Recent Developments—2012".*

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

"**Projects**" means the four wind power projects in the United States acquired by APCo from Gamesa. See *"General Development of the Business – Recent Developments—2012".*

"**PTAM**" means the Post Test Year Adjustment Mechanism. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Liberty Utilities: Electrical Distribution".*

"**Purchase Agreement**" means the asset purchase agreement by and between Sierra Pacific Power Company d/b/a NV Energy and Calpeco dated April 22, 2009 in relation to the California Utility. See *"General Development of the Business – Three Year History – Fiscal 2010".*

"**Purchase Agreements**" means 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. See *"General Development of the Business – Three Year History – Fiscal 2010".*

"**Put Date**" has the meaning ascribed thereto under *"Description of Capital Structure – Convertible Debentures – Series 3 Debentures".*

"**Put Price**" has the meaning ascribed thereto under *"Description of Capital Structure – Convertible Debentures – Series 3 Debentures".*

"**QFs**" means Qualifying Facilities. See *"Description of the Business – General Description of the Regulatory Regimes in which the Business Operates – Power Generation Regulatory Regimes".*

"**QF Status**" means Qualifying Facility status. See *"Risk Factors – Regulatory Climate and Permitting Risks – APCo".*

"**Québec AG**" means the Attorney General of Québec. See *"Risk Factors – Legal Proceedings—Côte Ste-Catherine Water Lease Dues"* .

"**PURPA**" means the Public Utilities Regulatory Policies Act. See *"Description of the Business – General Description of the Regulatory Regimes in which the Business Operates – Power Generation Regulatory Regimes".*

"**Red Lily I**" means a 26.4 MW wind generation facility in southeastern Saskatchewan. *"General Development of the Business – Significant Acquisitions and Investments – 2011 – Red Lily Wind Project"*.

"**Redemption Date**" means May 16, 2011. See *"General Development of the Business – Three Year History – Fiscal 2011".*

"**Region**" means the Region of Peel.

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

"**RGGI**" means the Regional Greenhouse Gas Initiative. See *"Risk Factors – Operational Risk Management – Specific Environmental Risks"*.

"**Rights Plan**" means APUC's Shareholders' Rights Plan adopted at the Meeting. See *"General Development of the Business – Three Year History – Fiscal 2010".*

"**RPPI**" means the Renewable Power Production Incentive program. See *"Description of the Business – General Description of the Regulatory Regimes in which the Business Operates – Power Generation Regulatory Regimes".*

"**run of the river**" means a facility where there is a continuous discharge of water without storage and release of water. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric".*

"S.E.N.C." has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**Sanger LLC**" means Algonquin Power Sanger LLC, a California limited liability company. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**Seaway Management**" means The St. Lawrence Seaway Management Corporation. See *"Risk Factors – Legal Proceedings—Côte Ste-Catherine Water Lease Dues".*

"**Senior Indebtedness**" has the meaning ascribed thereto under *"Description of Capital Structure – Convertible Debentures – Series 3 Debentures".*

"**Senior Indebtedness Postponement Provisions**" has the meaning ascribed thereto under *"Description of Capital Structure – Convertible Debentures – Series 3 Debentures".*

"**Senior Executives**" means two executives of APUC, Ian Robertson and Christopher Jarratt. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**Senior Unsecured Debentures**" means $135 million in senior unsecured debentures issued by APCo on July 25, 2011 by way of private placement. See *"General Development of the Business – Three Year History – Fiscal 2011".*

"**Series 1A Debentures**" means the 7.50% convertible unsecured subordinated debentures issued by the Corporation in connection with the Unit Exchange on October 27, 2009 due 2014. See *"General Development of the Business – Three Year History – Fiscal 2011".*

"**Series 2A Debentures**" means APUC's 6.35% convertible unsecured subordinated debentures due November 30, 2016. See *"General Development of the Business – Recent Developments – 2012".*

"**Series 2A Redemption Date**" means February 24, 2012. See *"General Development of the Business – Recent Developments – 2012".*

"**Series 3 Conversion Price**" means $4.20 per Common Share. See *"Description of Capital Structure – Convertible Debentures – Series 3 Debentures".*

"**Series 3 Debentures**" or the "**APUC Debentures**" means a public offering completed on December 2, 2009 of approximately $55 million principal amount of 7% convertible unsecured subordinated debentures due June 30, 2017. See *"General Development of the Business – Three Year History – Fiscal 2009".*

"**Series 3 Interest Payment Date**" means June 30 and December 31 in each year, commencing on June 30, 2010. See *"Description of Capital Structure – Convertible Debentures – Series 3 Debentures".*

"**Series 3 Maturity Date**" has the meaning ascribed thereto under *"Description of Capital Structure – Convertible Debentures – Series 3 Debentures".*

"**Series 3 Trust Indenture**" means the trust indenture dated as of December 2, 2009 between APUC and the Debenture Trustee. See *"Description of Capital Structure – Convertible Debentures".*

"**Shareholders**" means registered holders of shares of APUC. See *"Dividends – Dividend Reinvestment Plan."*.

"**Squa Pan Facility**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History – Fiscal 2010".*

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

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

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

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

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

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

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

"**Strategic Agreement**" means the strategic investment agreement between APUC and Emera entered into on April 29, 2011. See *"General Development of the Business – Three Year History – Fiscal 2011".*

"**Subscription Agreement**" has the meaning ascribed thereto under *"General Development of the Business – Significant Acquisitions and Investments – 2011 – California Utility Acquisition"*.

"**Subscription Agreement (Calpeco)**" has the meaning ascribed thereto under *"Description of Capital Structure – Common Shares"*.

"**Subscription Agreement (National Grid)**" has the meaning ascribed thereto under *"General Development of the Business – Significant Acquisitions and Investments – 2011 – New Hampshire Utility Acquisition"*

"**TCE**" means trichloroethylene. See *"Risk Factors – Operational Risk Management – Specific Environmental Risks"*.

"**TCEQ**" means the Texas Commission on Environmental Quality. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Utilities: Water and Wastewater".*

"**Tinker Facility**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History – Fiscal 2010".*

"**Tinker Assets**" means the 36.8MW of electrical generating assets of Tinker Gen Co. in New Brunswick. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**Tinker Gen Co.**" means Algonquin Tinker Gen Co., a Wisconsin company. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries".*

"**TMO**" means Transition Management Office. See *"Risk Factors – Acquisitions and Divestitures – Transition Management Office"*.

"**Trafalgar**" has the meaning ascribed thereto under "*General Development of the Business—Recent Developments – 2012 – Corporate – Business Associations with APMI and Senior Executives – Trafalgar"*.

"**Treasury Purchase**" means newly issued Plan Shares purchased from APUC under the Reinvestment Plan. See *"Dividends – Dividend Reinvestment Plan".*

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

"**Unit Exchange**" has the meaning ascribed thereto under *"General Development of the Business – General – The Unit Exchange".*

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

"**Vestas**" means Vestas-Canadian Wind Technology, Inc. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Wind Power".*

"**Water Services**" means Algonquin Water Services LLC. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Wind Farm Buyer**" means APFA. See *"Material Contracts"*.

"Wind Farm Seller" means Gamesa Energy USA, LLC, a Delaware limited liability company. See *"Material Contracts"*.

"**Windlectric**" means Windlectric Inc. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

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

"**WPPI**" means Wind Power Production Incentive. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Wind Power"*.

"**Yankee Gas**" means the Yankee Gas Service Company. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Thermal – Cogeneration"*.

Exhibit 99.2

Consolidated Financial Statements of
Algonquin Power & Utilities Corp.
For the years ended December 31, 2011 and 2010

MANAGEMENT'S REPORT

Financial Reporting

The preparation and presentation of the accompanying Consolidated Financial Statements, MD&A and all financial information in the Financial Statements are the responsibility of management and have been approved by the Board of Directors. The Financial Statements have been prepared in accordance with U.S. generally accepted accounting principles. Financial statements, by nature include amounts based upon estimates and judgments. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Management has prepared the financial information presented elsewhere in this document and has ensured that it is consistent with that in the consolidated financial statements.

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit Committee of the Board, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfill its responsibilities for financial reporting and internal controls related thereto. The Committee meets with management and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The Audit Committee reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders.

Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2011, 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 the Company maintained effective internal control over financial reporting as at December 31, 2011.

March 21, 2012

"Ian Robertson"
Chief Executive Officer

"David Bronicheski"
Chief Financial Officer

KPMG LLP
Chartered Accountants
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INDEPENDENT AUDITORS' REPORT

To the Shareholders of Algonquin Power & Utilities Corp.

We have audited the accompanying consolidated financial statements of Algonquin Power & Utilities Corp., which comprise the consolidated balance sheet as at December 31, 2011 and December 31, 2010, the consolidated statements of operations, comprehensive income (loss), equity, and cash flows for the years ended December 31, 2011 and December 31, 2010, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with US generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Algonquin Power & Utilities Corp. as at December 31, 2011 and December 31, 2010, and its consolidated results of operations and its consolidated cash flows for the years ended December 31, 2011 and December 31, 2010 in accordance with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada

March 21, 2012

Algonquin Power & Utilities Corp.
Consolidated Balance Sheets

(thousands of Canadian dollars)

	December 31, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 72,887	$ 4,749
Short term investments (note 1(e))	833	3,674
Accounts receivable net of allowance for doubtful accounts of $255 and $380 (note 22)	44,394	25,875
Due from related parties (note 15)	2,275	718
Prepaid expenses	5,620	3,546
Supplies and consumables inventory	2,714	—
Current portion of notes receivable	482	1,172
Current portion of deferred tax asset (note 14)	13,022	14,015
Current portion of tax receivable (note 14)	133	—
Current regulatory assets (note 8)	2,458	—
	144,818	53,749
Long-term investments and notes receivable (note 5)	39,820	37,179
Deferred non-current income tax asset (note 14)	67,671	74,006
Property, plant and equipment (note 6)	945,956	761,740
Intangible assets (note 7)	55,269	73,886
Goodwill	9,710	995
Restricted cash (note 1(f))	4,693	3,564
Deferred financing costs	8,503	5,991
Non-current regulatory assets (note 8)	2,571	2,484
Other assets	3,577	3,355
	$1,282,588	$1,016,949
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 8,382	$ 2,182
Accrued liabilities	47,102	29,534
Current regulatory liabilities	2,469	—
Due to related parties (note 15)	1,795	1,534
Dividends payable	9,566	5,719
Current portion of long-term liabilities (note 9)	1,624	70,490
Current portion of other long-term liabilities (note 11)	1,037	420
Current portion of advances in aid of construction (note 1(o))	604	591
Current portion of derivative instruments (note 22)	2,935	2,338
Current income tax liability (note 14)	407	200
Current portion of deferred credit	6,314	11,020
Deferred income tax liability (note 14)	723	514
	82,958	124,542
Long-term liabilities (note 9)	331,092	189,468
Convertible debentures (note 10)	122,297	181,760
Other long-term liabilities (note 11)	11,027	11,405
Advances in aid of construction (note 1(o))	74,547	54,524
Non-current regulatory liabilities (note 8)	19,184	—
Deferred non-current income tax liability (note 14)	53,231	79,442
Derivative instruments (note 22)	5,209	3,525
Deferred credits (note 14)	30,348	32,222
Equity (note 12):		
Shareholders' capital	975,263	795,329
Additional paid-in capital	1,525	1,612
Deficit	(366,080)	(357,035)
Accumulated other comprehensive loss	(96,510)	(99,845)
Total Equity attributable to shareholders of Algonquin Power and Utilities Corp.	514,198	340,061
Non-controlling interest (note 3(a))	38,497	—
Total Equity	552,695	340,061
Commitments and contingencies (note 18)		
Subsequent events (notes 3, 6, 7, 8, 9, 10 and 12)		
	$1,282,588	$1,016,949

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Operations

(thousands of Canadian dollars, except per share amounts)

	2011	2010
Revenue:		
Non-regulated energy sales	$134,232	$129,977
Regulated energy sales and distribution	77,368	—
Waste disposal fees	16,406	9,039
Regulated water reclamation and distribution	44,989	38,011
Other revenue (note 17)	3,643	3,331
	276,638	180,358
Expenses		
Operating	88,420	69,568
Regulated commodities purchased	46,508	—
Non-regulated fuel for generation	24,628	25,929
Depreciation of property, plant and equipment	39,393	36,471
Amortization of intangible assets	6,433	10,144
Administrative expenses	17,534	14,886
Write down of long-lived assets (notes 6 and 7)	16,520	2,492
Gain on foreign exchange	(652)	(528)
	238,784	158,962
Operating income	37,854	21,396
Interest expense	30,441	24,839
Interest, dividend income and other income (notes 16)	(5,659)	(5,164)
Acquisition related costs	2,965	3,015
Loss on derivative financial instruments (note 22 (c))	5,844	1,103
	33,591	23,793
Earnings (loss) from operations before income taxes	4,263	(2,397)
Income tax expense (recovery) (note 14)		
Current	300	(69)
Deferred	(23,339)	(20,722)
	(23,039)	(20,791)
Net earnings	27,302	18,394
Net earnings attributable to non-controlling interests	3,921	444
Net earnings attributable to shareholders of Algonquin Power & Utilities Corp.	$ 23,381	$ 17,950
Basic net earnings per share (note 19)	$ 0.20	$ 0.19
Diluted net earnings per share (note 19)	$ 0.20	$ 0.19

See accompanying notes to consolidated financial statements

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

(thousands of Canadian dollars)

	2011	2010
Net Earnings	$27,302	$ 18,394
Other comprehensive income (loss), before tax:		
Foreign currency translation adjustment due to accounting change (note 1(t))	—	(37,605)
Increase in unfunded pension obligation (note 1(q))	(48)	—
Foreign currency translation adjustment	4,272	(13,528)
Other comprehensive income, before tax:	4,224	(51,133)
Income tax expense related to items of other comprehensive income	—	—
Other comprehensive income (loss), net of tax:	4,224	(51,133)
Comprehensive income (Loss)	31,526	(32,739)
Less: comprehensive income attributable to the non-controlling interest	4,810	(444)
Comprehensive income (loss) attributable to shareholders of Algonquin Power & Utilities Corp	$26,716	$(33,183)

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Cash Flows

(thousands of Canadian dollars)

	2011	2010
Cash provided by (used in):		
Operating Activities:		
Net earnings	$ 27,302	$ 18,394
Adjustments and items not affecting cash:		
Depreciation of property, plant and equipment	39,393	36,471
Amortization of intangible assets	6,433	10,144
Other amortization	2,192	2,148
Gain on sale of assets	(357)	—
Deferred taxes	(23,339)	(20,722)
Unrealized loss (gain) on derivative financial instruments	2,324	(7,142)
Share-based compensation	769	108
Write down of long-lived assets	16,520	2,492
Unrealized foreign exchange gain	—	(414)
Changes in non-cash operating items (note 20)	(1,542)	(85)
	69,695	41,394
Financing Activities:		
Cash dividends (note 13)	(28,582)	(18,901)
Cash distributions to non-controlling interest	(523)	(444)
Issuance of common shares	118,846	—
Deferred financing costs	(3,642)	(1,194)
Increase in long-term liabilities	204,759	98,787
Decrease in long-term liabilities	(134,932)	(80,078)
Increase in advances in aid of construction	6,288	4,857
Decrease in other long-term liabilities	(297)	(342)
	161,917	2,685
Investing Activities:		
Decrease / (increase) in restricted cash	(1,036)	575
Decrease / (increase) in short-term investments	(833)	36,212
Increase in other assets	(2,438)	(90)
Distributions received in excess of equity income	3,839	882
Receipt of principal on notes receivable	1,172	410
Increase in non-controlling interest	1,351	—
Proceeds from liquidation of Highground assets	1,073	170
Increase in long-term investments and notes receivable	(6,900)	(14,759)
Proceeds from sale of property, plant and equipment	1,583	—
Additions to property, plant and equipment	(60,745)	(20,789)
Acquisitions of operating entities (note 3(a))	(100,058)	(44,397)
	(162,992)	(41,786)
Effect of exchange rate differences on cash	(482)	(126)
Increase in cash and cash equivalents	68,138	2,167
Cash and cash equivalents, beginning of the period	4,749	2,582
Cash and cash equivalents, end of the period	$ 72,887	$ 4,749
Supplemental disclosure of cash flow information:		
Cash paid during the period for interest expense	$ 28,143	$ 21,562
Cash paid during the period for income taxes	$ 195	$ (285)
Non-cash transactions		
Property, plant and equipment acquisitions in accruals	$ 8,556	$ —

See accompanying notes to consolidated financial statements

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

For the year ended December 31, 2011:

	Common Shares	Additional paid-in capital	Accumulated Deficit	Accumulated OCI	Non-controlling interests	Total
Balance, December 31, 2010	$795,329	$ 1,612	$ (357,035)	$ (99,845)	$ —	$340,061
Dividends declared and distributions to non-controlling interests	—	—	(32,426)	—	(523)	(32,949)
Conversion and redemption of convertible debentures	59,973	(815)	—	—	—	59,158
Issuance of common shares	118,888	—	—	—	—	118,888
Stock compensation expense	—	728	—	—	—	728
Acquisition of Liberty Energy (California)	—	—	—	—	34,210	34,210
Amounts received in connection with Highground transaction (note 3 (h))	1,073	—	—	—	—	1,073
Net earnings			23,381		3,921	27,302
Other comprehensive income	—	—	—	3,335	889	4,224
Balance, December 31, 2011	$975,263	$ 1,525	$ (366,080)	$ (96,510)	$ 38,497	$552,695

For the year ended December 31, 2010:

	Common Shares	Additional paid-in capital	Accumulated Deficit	Accumulated OCI (CTA)	Non-controlling interests	Total
Balance, December 31, 2009	$785,828	$ 1,487	$ (352,220)	$ (48,712)	$ —	$386,383
Dividends declared and distributions to non-controlling interests	—	—	(22,765)	—	(444)	(23,209)
Conversion and redemption of convertible debentures	4,568	17	—	—	—	4,585
Stock compensation expense	—	108	—	—	—	108
Amounts received in connection with Highground transaction (note 3 (h))	170	—	—	—	—	170
Issuance pursuant to management internalization	4,763	—	—	—	—	4,763
Net earnings			17,950		444	18,394
Other comprehensive loss	—	—		(51,133)	—	(51,133)
Balance, December 31, 2010	$795,329	$ 1,612	$ (357,035)	$ (99,845)	$ —	$340,061

Algonquin Power & Utilities Corp. ("APUC" or the "Company") is an incorporated entity under the Canada Business Corporations Act. APUC's principal activity is the ownership of power generation facilities and water, gas and energy utilities, through investments in securities of subsidiaries including corporations, limited partnerships and trusts which carry on these businesses. The activities of the subsidiaries may be financed through equity contributions, interest bearing notes and third party project debt as described in the notes to the consolidated financial statements.

APUC's power generation business unit conducts business under the name Algonquin Power Co. ("APCo"). APCo owns or has interests in renewable energy facilities and thermal energy facilities representing more than 450 MW of installed electrical generation capacity. APUC's Utility Services business unit conducts business under the name of Liberty Utilities Co. ("Liberty Utilities"). Liberty Utilities businesses operate under two separately managed regions – Liberty Utilities (South) (formerly known as Liberty Water) and Liberty Utilities (West) (formerly known as Liberty Energy - Calpeco). Liberty Utilities (South) currently owns a portfolio of utilities in the United States of America providing water or wastewater services in the states of Arizona, Texas, Missouri and Illinois. Liberty Utilities (West) currently owns a 50.001% interest in an electric distribution utility serving the Lake Tahoe region of California (the "California Utility"). APUC has announced an agreement to acquire, subject to regulatory approval, the remaining 49.999% interest in the California Utility (see note 3 (a)). Liberty Utilities has also announced an agreement to acquire, subject to regulatory approval, Granite State Electric Company, a New Hampshire electric distribution company, and EnergyNorth Natural Gas Inc., a regulated natural gas distribution utility (see note 3 (b)).

The regulated utility operating companies owned by Liberty Utilities are subject to rate regulation generally overseen by the public utility commissions of the states in which they operate (see note 8).

1. Significant accounting policies

(a) Basis of preparation:

The accompanying consolidated financial statements and accompanying notes have been prepared in accordance with U.S. generally accepted accounting principles in the United States ("U.S. GAAP") and follow disclosures required under Regulation S-X provided by the Securities and Exchange Commission ("SEC"). These are the Company's first U.S. GAAP annual consolidated financial statements.

The Company's consolidated financial statements were prepared in accordance with Canadian Generally Accepted Accounting Principles ("Canadian GAAP") until December 31, 2010. Canadian GAAP differs in some areas from U.S. GAAP as was disclosed in the reconciliation to U.S. GAAP included in the audited annual financial statements for the year ended December 31, 2010. The accounting policies set out below have been consistently applied under U.S. GAAP to all the periods presented. The comparative figures in respect of 2010 were restated to reflect the adoption of U.S. GAAP.

(b) Basis of consolidation:

The accompanying consolidated financial statements of APUC include the accounts of APUC and its wholly owned subsidiaries and variable interest entities ("VIEs") where the Company is the primary beneficiary. Intercompany transactions and balances have been eliminated.

(c) Accounting for rate regulated operations:

APUC's regulated utility operating companies are accounted for under the principles of U.S. Financial Accounting Standards Board ASC Topic 980 Regulated Operations ("ASC 980"). Under ASC 980, regulatory assets and liabilities that would not be recorded under U.S. GAAP for non-regulated entities are recorded to the extent that they represent probable future revenues or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate making process. Management believes the regulatory assets recorded in these financial statements are probable of recovery either because the Utilities received prior Regulator approval or due to regulatory precedent set for similar circumstances. Included in Note 8, Regulatory Assets & Liabilities are details of regulatory assets and liabilities, and their current regulatory treatment.

Under ASC 980, an allowance for funds used during construction projects that are included in rate base is capitalized. This allowance is designed to enable a utility to capitalize financing costs during periods of construction of property subject to rate regulation to the extent permitted by the regulator. It represents the cost of borrowed funds (allowance for borrowed funds used during construction) and a return on other funds (allowance for equity funds used during construction).

The electric utilities' and the water utilities' accounts are maintained in accordance with the Uniform System of Accounts prescribed by the FERC and NARUC, respectively.

(d) Cash and cash equivalents:

Cash and cash equivalents include all highly liquid instruments with an original maturity of three months or less.

1. Significant accounting policies (continued)

(e) Short term investments:

Short term investments, consist of money market instruments with maturities commencing from January 2012 and are recorded at current market value. Included in short term investments is an investment of $nil (U.S. $nil) which is denominated in U.S. dollars (December 31, 2010 - $3,674 (U.S. $3,694)).

(f) Restricted cash:

Restricted cash represent reserves and amounts set aside pursuant to requirements of various debt agreements. Cash reserves segregated from APUC's cash balances are maintained in accounts administered by a separate agent and disclosed separately as restricted cash in these consolidated financial statements. APUC cannot access restricted cash without the prior authorization of parties not related to APUC.

(g) Accounts receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. The Company maintains an allowance for doubtful accounts for estimated losses inherent in its accounts receivable portfolio. In establishing the required allowance, management considers historical losses adjusted to take into account current market conditions and customers' financial condition, the amount of receivables in dispute, and the current receivables aging and current payment patterns. Account balances are charged against the allowance after all means of collection have been exhausted and the potential for recovery is considered remote. The Company does not have any off-balance-sheet credit exposure related to its customers.

(h) Supplies and consumables inventory

Supplies and consumables inventory (other than capital spares and rotatable spares, which are included in property, plant, and equipment) are charged to inventory when purchased and then capitalized to plant or expensed, as appropriate, when installed, used or become obsolete. These items are stated at the lower of cost and replacement cost.

(i) Property, plant and equipment:

Property, plant and equipment, consisting of renewable and thermal generation assets, electrical, water and wastewater distribution assets, equipment and land, are recorded at cost. The costs of acquiring or constructing property, plant and equipment include the following: materials, labour, contractor and professional services, construction overhead directly attributable to the capital project (where applicable), interest for non-regulated property and allowance for equity funds used during construction ("AFUDC") for regulated property. Plant and equipment under capital leases are stated at the present value of minimum lease payments.

AFUDC reflects the cost of debt or equity funds used to finance construction and only is capitalized as part of the cost of regulated utility plant where such treatment is permitted by the regulator. AFUDC amounts capitalized are included in rate base for establishing utility rates. For operations that do not apply regulatory accounting, interest related only to debt is capitalized as a cost of construction in accordance with ASC 835. The interest capitalized that relates to debt reduces interest expense on the income statement. The AFUDC capitalized that relates to equity funds is recorded as interest, dividend and other income on the Statement of Operations.

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

1. Significant accounting policies (continued)

(i) Property, plant and equipment (continued):

The Company's depreciation is based on the estimated useful lives of the depreciable assets in each category and is determined using the straight-line method. The range of estimated useful lives and the weighted average useful lives are summarized below:

	Range of useful lives		Weighted average useful lives	
	2011	2010	2011	2010
Generation				
Renewable	3 – 60	3 – 60	31	31
Thermal	3 – 40	3 – 40	22	22
Distribution				
Electrical	15 – 75	N/A	52	N/A
Water & wastewater	5 – 50	5 – 50	25	25
Equipment	5 – 50	5 – 50	24	24

Contributions in aid of construction represent amounts contributed by customers and governments for the cost of utility capital assets. It also includes amounts initially recorded as advances in aid of construction but where the advance repayment period has expired. These contributions are recorded as a reduction in the cost of utility assets and are amortized at the rate of the related asset.

In accordance with regulator-approved accounting policies, when depreciable property, plant and equipment of Liberty Utilities are replaced or retired, the original cost plus any removal costs incurred (net of salvage) are charged to accumulated depreciation with no gain or loss reflected in results of operations. Gains and losses will be charged to results of operation in the future through adjustments to depreciation expense. In the absence of regulator-approved accounting policies, gains and losses on the disposition of property, plant and equipment are charged to earnings as incurred.

(j) Intangibles:

The fair value of power sales contracts and energy sales contracts acquired in business combinations are amortized on a straight-line basis over the remaining term of the contract. These periods range from 6 to 25 years from date of acquisition for power sales contracts and 12 months for energy sales contracts.

Customer relationships acquired in business combinations are amortized on a straight-line basis over their estimated life of 40 years.

1. Significant accounting policies (continued)

(k) Goodwill:

Goodwill represents the excess of the purchase price of an acquired business over the fair value of the net assets acquired. Goodwill is not included in rate-base and is not amortized.

In accordance with ASC Update No. 2011-08 “Intangibles-Goodwill and Other (Topic 350), Testing Goodwill for Impairment” issued by the FASB in September 2011, the Company annually assesses qualitative factors to determine whether it is more likely than not that the fair value of goodwill is less than its carrying amount. If it is more likely than not that its fair value is less than its carrying amount, the Company calculates the fair value of the reporting unit. The carrying amount of the reporting unit’s goodwill is considered not recoverable if the carrying amount of the reporting unit as a whole exceeds the reporting unit’s fair value. An impairment charge is recorded for any excess of the carrying value of the goodwill over the implied fair value. Goodwill is tested for impairment between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount.

(l) Impairment of long-lived assets:

APUC reviews property, plant and equipment and intangible assets for impairment whenever events or changes in circumstances indicate the carrying amount may not be recoverable.

Assets Held and Used: Recoverability of assets held and used is measured by comparing the carrying amount of an asset to undiscounted expected future cash flows. If the carrying amount exceeds the recoverable amount, the asset is written down to its fair value.

Assets Held for Sale: Recoverability of assets held for sale is measured by comparing the carrying amount of an asset to its fair value less the cost to sell. If the carrying amount exceeds the recoverable amount, the asset is written down to its fair value less estimated costs to sell.

(m) Variable interest entities:

The Company performs analysis to assess whether its operations and investments represent variable interest entities (“VIEs”). To identify potential VIEs, management reviews contracts under leases, long-term purchase power agreements, tolling contracts and jointly-owned facilities. VIEs of which the Company is deemed the primary beneficiary are consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the obligation to absorb losses of the entity that could potentially be significant to the entity. In circumstances where APUC is not deemed the primary beneficiary, the VIE is not consolidated.

Long Sault is a hydroelectric generating facility in which APUC acquired its interest by way of subscribing to two notes from the original developers. The notes receivable effectively provide APUC the right to 100% of after tax cash flows of the facility up to 2013, 65% from 2014 to 2027 and 58% thereafter. The Company also has the right to acquire 58% of the equity in the facility at the end of the term of the notes in 2038. APUC has determined that the facility is a VIE, since the Company is the primary beneficiary and therefore the Long Sault entity is subject to consolidation by the Company. Total generating assets and long-term debt of Long Sault amount to $46,160 (2010 -$47,757) and to $38,136 (2010 -$39,033), respectively. The financial performance of Long Sault reflected on the statement of operations includes non-regulated energy sales of $9,804 (2010 -$7,037), operating expenses and amortization of $3,001 (2010 -$2,572) and interest expense of $3,984 (2010 -$4,126).

1. Significant accounting policies (continued)

(n) Long-term investments and notes receivable:

Investments in which APUC has significant influence but not control or joint control are accounted using the equity method. APUC records its share in the income or loss of its investees in interest, dividend and other income in the Consolidated Statement of Operations. All other equity investments where APUC does not have significant influence or control are accounted for under the cost method. Under the cost method of accounting, investments are carried at cost and the carrying amounts are adjusted only for other-than-temporary declines in value and additional investments. Income is recorded when dividends are received.

Notes receivable are financial assets with fixed or determined payments that are not quoted in an active market. Notes receivable that exceed one year and bear interest at a market rate based on the customer's credit quality are initially recorded at cost, which is generally face value. Subsequent to acquisition, they are recorded at amortized cost using the effective interest method. The Company acquired these notes receivable as long-term investments and does not intend to sell these instruments prior to maturity.

An allowance for impairment loss on notes receivable is recorded if it is expected that the Company will not collect all principal and interest contractually due. The impairment is measured based on the present value of expected future cash flows discounted at the note's effective interest rate. The Company does not accrue interest when a note is considered impaired. When ultimate collectability of the principal balance of the impaired note is in doubt, all cash receipts on impaired notes are applied to reduce the principal amount of such notes until the principal has been recovered and are recognized as interest income thereafter. Impairment losses are charged against the allowance and increases in the allowance are charged to bad debt expense. Notes are written off against the allowance when all possible means of collection have been exhausted and the potential for recovery is considered remote.

(o) Advances in aid of construction:

The Company has various agreements with real estate development companies conducting business within the Company's service territories (the "developers"), whereby funds are advanced to the Company by the developers to assist with funding some or all of the costs of the development. These amounts are recorded as Advances in Aid of Construction in other long-term liabilities. In many instances, developer advances are subject to refund but the refund is non-interest bearing. Refunds of developer advances are made over periods ranging from 10 to 20 years. Generally, advances not refunded within the prescribed period are not required to be repaid. After the prescribed period has lapsed, any remaining unpaid balance is transferred to contributions in aid of construction and recorded as an offsetting amount to cost of property, plant and equipment. In 2011, $1,107 (2010 - $nil) was transferred from advances in aid of construction to contributions in aid of construction.

(p) Other long-term liabilities:

Other long-term liabilities include deferred water rights. Deferred water rights are related to a hydroelectric generating facility which has a fifty year water lease with the first ten years of the water lease requiring no payment, which is a form of lease inducement. An annual average rate for water rights was estimated for the entire life of the lease and that average rate is being expensed over the lease term. The result of this policy is that the deferred water rights inducement amount recorded in the first ten years is being drawn down in the last forty years.

1. Significant accounting policies (continued)

(p) Other long-term liabilities (continued):

Other long term liabilities also include customer deposits. Customer deposits result from the Liberty Utilities' obligation by state regulators to collect a deposit from customers of its facilities under certain circumstances when services are connected. The deposits are refundable as allowed under the facilities' regulatory agreement. The deposits bear monthly interest and are applied to the customer account after 12 months if the customer is found to be credit worthy.

(q) Pension plan:

Liberty Utilities (West) has a defined benefit cash balance pension plan covering substantially all its employees, under which employees are credited with a percentage of base pay plus a prescribed interest rate credit. The plan interest credit rate varies from year-to-year based on the five-year U.S. Treasury bonds yield plus 0.25%. Employees' benefits under the plan are fully vested upon completion of three years of service. The Company's policy is to make contributions within the range determined by generally accepted actuarial principles. The costs of the Company's pension for employees are expensed over the periods during which employees render service. The Company recognizes the funded status of its defined-benefit plan on the consolidated balance sheet and recognizes changes in funded status in the year the change occurs. The Company recognizes the unamortized gains and losses and past service costs in Accumulated other comprehensive income ("AOCI"). The projected benefit obligation of $230 exceeds the fair value of the plan assets of $200 as at December 31, 2011. Benefit cost of $182 and actuarial loss of $48 are reflected in earnings and other comprehensive income, respectively. The assumptions used in calculating the pension obligation include a discount rate of 4%, expected return on plan assets of 6% and rate of compensation increase of 4%. As at December 31, 2011, plan assets are invested in fixed income securities.

(r) Asset retirement obligations:

The Company completes periodic reviews of potential asset retirement obligations that may require recognition. The fair value of estimated asset retirement obligations is recognized in the consolidated balance sheet when identified and a reasonable estimate of fair value can be made. The asset retirement cost, equal to the estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. The asset retirement costs are depreciated over the asset's estimated useful life and are included in amortization expense on the Consolidated Statements of Operations. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the Consolidated Statements of Operations. Actual expenditures incurred are charged against the accumulated obligation. Based on APUC's assessments the Company does not have any significant asset retirement obligations and therefore no provision for retirement obligations have been recorded.

(s) Recognition of revenue:

Revenue derived from non-regulated energy generation sales, which are mostly under long-term power purchase contracts, is recorded at the time electrical energy is delivered.

1. Significant accounting policies (continued)

(s) Recognition of revenue (continued):

Water reclamation and distribution revenues are recorded when water is processed or delivered to customers. At the end of each month, the water delivered and waste water collected from the customers from the date of their last meter read to the end of the month is estimated and the corresponding unbilled revenues are calculated. These estimates of unbilled revenues are based on the ratio of billable days versus unbilled days, amount of water procured and collected during that month, historical customer class usage patterns and current tariffs.

Revenues related to utility energy sales and distribution are recorded based on metered energy consumptions by customers, which occurs on a systematic basis throughout a month, rather than when the service is rendered or energy is delivered. At the end of each month, the energy delivered to the customers from the date of their last meter read to the end of the month is estimated and the corresponding unbilled revenues are calculated. These estimates of unbilled sales and revenues are based on the ratio of billable days versus unbilled days, amount of energy procured and generated during that month, historical customer class usage patterns, line loss and current tariffs.

Revenue from waste disposal is recognized on actual tonnage of waste delivered to the plant at prices specified in the contract. Certain contracts include price reductions if specified thresholds are exceeded. Revenue for these contracts is recognized based on actual tonnage at the expected price for the contract year.

Interest from long-term investments is recorded as earned.

(t) Foreign currency translation:

The Company's reporting currency is the Canadian dollar.

The Company's US operations are determined to have the U.S. dollar as their functional currency since the preponderance of operating, financing and investing transactions are denominated in U.S. dollars. The financial statements of these operations are translated into Canadian dollars using the current rate method, whereby assets and liabilities are translated at the rate prevailing at the balance sheet date while revenues and expenses are converted using average rates for the period. Unrealized gains or losses arising as a result of the translation of the financial statements of these entities are reported as a component of other comprehensive income ("OCI") and are accumulated in a component of equity on the consolidated balance sheet and are not recorded in income unless there is a complete sale or substantially complete liquidation of the investment.

As a result of the change relating to conversion of the Company from an income trust to a corporate structure at the end of 2009, the Company re-evaluated its exposure to currency exchange rate changes as determined by the underlying facts and circumstances of the economy in which the US divisions operate. The Company concluded that the functional currency of the US operations of the Renewable Energy and Thermal Energy divisions has become the U.S. dollar. Consequently, these divisions have been prospectively translated into Canadian dollars using the current rate method, effective January 1, 2010. The net exchange adjustment of $37,605 resulting from the current rate translation of non-monetary items, principally property, plant and equipment and intangible assets, as of the date of the change is included as a separate component of other comprehensive income with a corresponding reduction to the carrying amount of the non-monetary items.

1. Significant accounting policies (continued)

(u) Stock Based Compensation

The Company has several share-based compensation plans: a share option plan; an employee common share purchase plan ("ESPP"); a deferred share unit ("DSU") plan; and a performance share unit ("PSU") plan. The Company recognizes all employee stock-based compensation as a cost in the financial statements. Equity classified awards are measured at the grant date fair value of the award. The Company estimates grant date fair value using the Black-Scholes option pricing model. Liability classified awards are measured at fair value based on the average common share price over the five days immediately preceding the date of issue and at the end of the reporting period using the average over the days ending on the financial statement date.

(v) Income taxes:

Income taxes are accounted for using the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. A valuation allowance is recorded against deferred tax assets to the extent that it is considered more likely than not that the deferred tax asset will not be realized. The effect on deferred assets and liabilities of a change in tax rates is recognized in earnings in the period that includes the date of enactment. Income tax credits are treated as a reduction to current income tax expense in the year the credit arises or future periods to the extent that realization of such benefit is more likely than not.

The organizational structure of APUC and its subsidiaries is complex and the related tax interpretations, regulations and legislation in the tax jurisdictions in which they operate are continually changing. As a result, there can be tax matters that have uncertain tax positions. The Company follows FASB ASC 740-10 and recognizes the effect of income tax positions only if those positions are more likely than not of being sustained. Recognized income tax positions are measured at the largest amount that is greater than 50% likely of being realized. Changes in recognition or measurement are reflected in the period in which the change in judgment occurs.

(w) Financial instruments and derivatives:

APUC has classified its cash and cash equivalents, short term investments, and restricted cash as held-for-trading, which are measured at fair value. Accounts receivable and notes receivable are measured at amortized cost and there is no liquid market for these investments. Long-term liabilities, convertible debentures, and other long-term liabilities are measured at amortized cost using the effective interest method, adjusted for the amortization or accretion of premiums or discounts.

Transaction costs that are directly attributable to the acquisition of financial assets are accounted for as part of the respective asset's carrying value at inception. Transaction costs for items classified as held-for-trading are expensed immediately. Transaction costs that are directly attributable to the issuance of financial liabilities, costs of arranging the Company's credit facility and costs considered as commitment fees paid to financial institutions are recorded in deferred financing costs. Deferred financing costs, premiums and discounts on long- term debt are amortized using the effective interest method while deferred financing costs relating to revolving credit facilities are amortized on a straight-line basis over the term of the facility.

1. Significant accounting policies (continued)

(w) Financial instruments and derivatives (continued):

The Company uses derivative financial instruments as one method to manage exposures to fluctuations in exchange rates, interest rates and commodity prices. APUC recognizes all derivative instruments as either assets or liabilities in the Consolidated Balance Sheet at their respective fair values and the change in fair value is included in the Consolidated Statements of Operations. None of the derivatives were designated in hedging relationships for accounting purposes. The Company's derivative program is not designed or operated for trading or speculative purposes.

Liberty Utilities (West) enters into Power Purchase Agreements ("PPA") for load serving requirements. These contracts meet the exemption for normal purchase and normal sales and as such, are not required to be marked-to-market and are accounted for on an accrual basis. We evaluate our counterparties on an on-going basis for non-performance risk to ensure it does not impact our conclusion with respect to this exemption.

(x) Fair Value Measurements

The Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs to the extent possible. The Company determines fair value based on assumptions that market participants would use in pricing an asset or liability in the principle or most advantageous market. When considering market participant assumptions in fair value measurements, the following fair value hierarchy distinguishes between observable and unobservable inputs, which are categorized in one of the following levels:

- Level 1 Inputs: Unadjusted quoted prices in active markets for identical assets or liabilities accessible to the reporting entity at the measurement date.
- Level 2 Inputs: Other than quoted prices included in Level 1 inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the asset or liability.
- Level 3 Inputs: Unobservable inputs for the asset or liability used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at measurement date.

(y) Commitments and Contingencies

Liabilities for loss contingencies arising from claims, assessments, litigation, fines, and penalties and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Legal costs incurred in connection with loss contingencies are expensed as incurred.

1. Significant accounting policies (continued)

(z) Use of estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of these financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the years presented, management has made a number of estimates and valuation assumptions, including the useful lives and recoverability of property, plant and equipment and intangible assets, the recoverability of notes receivable and long-term investments, the recoverability of deferred tax assets, assessments of asset retirement obligations, and the fair value of financial instruments, derivatives, share-based compensation and contingent consideration. These estimates and valuation assumptions are based on present conditions and management's planned course of action, as well as assumptions about future business and economic conditions. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

2. Recently issued accounting pronouncements

(a) Recently Adopted Accounting Pronouncements

In December 2010, the FASB issued ASC update No. 2010-28, "Intangibles-Goodwill and Other (Topic 350), When to Perform Step 2 of the Goodwill Impairment Test for Reporting Units with Zero or Negative Carrying Amounts, a consensus of the FASB Emerging Issues Task Force." This amendment modifies guidance for Step 1 of the goodwill impairment test for reporting units with zero or negative carrying amounts. The adoption of this update did not have a material impact on the Company's financial statements.

In December 2010, the FASB issued ASC update No. 2010-29, "Business Combinations (Topic 805), Disclosure of Supplementary Pro Forma Information for Business Combinations, a consensus of the FASB Emerging Issues Task Force." This amendment clarifies the periods for which pro forma financial information is presented. The acquisition of the California Utility occurred on January 1, 2011 and therefore the Statement of Operations for the year ended December 31, 2011 contains a full year of operating results from this acquisition. Accordingly pro forma financial statements would not provide any additional information. As the business combination was an acquisition of a division of the vendor for which comparable results from operations for the previous year are not available, pro forma financial statements for the comparative period are not provided as they cannot be practicably obtained. The adoption of this update did not have a material impact on the Company's financial statements.

In September 2011, the FASB issued ASC update No. 2011-08 "Intangibles-Goodwill and Other (Topic 350), Testing Goodwill for Impairment". This Update revises how an entity tests goodwill for impairment. The new guidance allows an entity to first assess qualitative factors to determine whether it is necessary to perform the two-step quantitative goodwill impairment test. An entity is no longer required to calculate the fair value of a reporting unit unless the entity determines, based on a qualitative assessment, that it is more likely than not that its fair value is less than its carrying amount. As permitted by the Update, the Company has early adopted this standard in these annual financial statements for the year ended December 31, 2011. The adoption of this update did not have a material impact on the Company's financial statements.

2. Recently issued accounting pronouncements (continued)

(a) Recently Adopted Accounting Pronouncements (continued)

In June 2011, the FASB issued ASC update No. 2011-05 “Presentation of Comprehensive income (Topic 220)”. This Update provides accounting guidance on presentation of comprehensive income. The new guidance eliminates the current option to report Other comprehensive income (“OCI”) and its components in the statement of changes in stockholders’ equity. The new guidance requires the changes in OCI be presented either in a single continuous statement of net income and OCI or in two separate but consecutive statements. As permitted by the Update, the Company has early adopted the presentation guidance in these annual financial statements for the year ended December 31, 2011. The amendments resulted in presentation changes only in the consolidated financial statements.

Subsequently in December 2011, the FASB issued ASC update No. 2011-12, “Deferral of the Effective Date for Amendments to Presentation of Reclassification of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05”. The amendments in ASU No. 2011-12 defer the changes in ASU No. 2011-05 that relate to the presentation of reclassification adjustments out of AOCI.

(b) Recent Accounting Guidance Not Yet Adopted

In December 2011, the FASB issued ASU 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities. This newly issued accounting standard requires an entity to disclose both gross and net information about instruments and transactions eligible for offset in the statement of financial position as well as instruments and transactions executed under a master netting or similar arrangement and was issued to enable users of financial statements to understand the effects or potential effects of those arrangements on its financial position. This ASU is required to be applied retrospectively and is effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013. As this accounting standard only requires enhanced disclosure, the adoption of this standard is not expected to have an impact our financial position or results of operations.

In May 2011, the FASB issued ASC update No. 2011-04 “Fair Value Measurement (Topic 820)”. This Update amends the accounting and disclosure requirements for fair value measurements. The new guidance expands the disclosures about fair value measurements categorized within Level 3 of the fair value hierarchy and requires categorization by level of the fair value hierarchy for items that are not measured at fair value in the statement of financial position but for which the fair value is required to be disclosed. The new guidance will be effective for the Company’s quarter ending March 31, 2012, and will be applied prospectively. Other than requiring additional disclosures, the adoption of this guidance is not expected to have a material impact on the Company’s consolidated financial statements.

3. Acquisitions

(a) Acquisition of California electrical generation and regulated distribution utility

On January 1, 2011, APUC and Emera Inc. ("Emera") closed the acquisition of the "California Utility" for a purchase price of approximately $135,343 (U.S. $136,077). Through its wholly owned subsidiary Liberty Energy (California), APUC owns 50.001% of the shares of California Pacific Utility Ventures LLC, which acquired the California Utility and has concluded it controls the acquired entity. Liberty Energy (California) provides electric distribution service to approximately 47,000 customers in the Lake Tahoe region. The other 49.999% of the shares were acquired by Emera in the same transaction. The acquisition has been accounted for using the acquisition method, with earnings from operations consolidated since the date of acquisition.

On April 29, 2011, Emera agreed to sell its 49.999% interest in Liberty Energy (California) to APUC in exchange for 8,211,000 shares of APUC. The transaction is subject to regulatory approval and is expected to close in 2012.

The following table summarizes the preliminary allocation of the assets acquired and liabilities assumed at the acquisition date, as well as the fair value at the acquisition date of the non-controlling interest in Liberty Energy (California):

Working capital	$ 8,964
Property, plant and equipment	146,064
Deferred income tax asset	2,056
Goodwill	8,268
Current portion of other long-term liabilities	(671)
Advances in aid of construction	(10,434)
Other long-term liabilities	(1,988)
Regulatory liabilities	(16,916)
Total net assets acquired	$135,343

The acquisition was funded as follows:

Contribution of equity by APUC in 2011	$ 29,074
Contribution of equity by APUC in 2010	3,787
Non-controlling interest portion of purchase price paid by Emera	32,860
Debt financing	69,622
Total acquisition consideration	$135,343

In connection with the acquisition, the Company issued 8,523,000 shares at a price of $3.25 per share to Emera pursuant to a subscription receipt agreement. The $27,700 cash proceeds of the subscription receipts were used to fund a portion of the cost of acquisition of the California Utility.

The determination of the fair value of assets and liabilities acquired has been based upon fair value measurements.

Goodwill is calculated as the excess of the purchase price over the fair value of net assets acquired and the contributing factors to the amount recorded include expected future cash flows, potential operational synergies, the utilization of technology, and cost savings opportunities in the delivery of certain shared administrative and other services. All of the goodwill was allocated to the Liberty Utilities (West) segment.

3. Acquisitions (continued)

(a) Acquisition of California electrical generation and regulated distribution utility (continued):

Property, plant & equipment of Liberty Energy (California) are amortized on a straight line basis, ranging from 15 to 75 years in accordance with regulatory requirements.

The Company incurred $2,572 in total acquisition-related costs (2010 - $2,210); of which $362 were incurred during 2011. All such costs have been expensed in the consolidated Statement of Operations.

As the acquisition closed on January 1, 2011, the financial statements for the year ended December 31, 2011 contain a full year of operating results for the utility. Liberty Energy (California) contributed revenue of $77,367 and earnings of $2,987 to the Company's results for the year ended December 31, 2011. The disclosure of pro forma revenue and earnings related to 2010 is impracticable since the assets acquired were part of a small division of a much larger utility; separate financial statements were not maintained by the vendor of the assets, the regulated tariff driving revenue formulae has changed, the rate-base used in determining rates was not identical to the assets acquired and the operating costs were subject to extensive allocation.

(b) Acquisition of Regulated Water Utilities

On September 20, 2011, Liberty Utilities (South) completed the acquisition of the water utility assets of Noel Water Co., Inc. ("Noel"). The acquisition has been accounted for using the acquisition method, with earnings from operations consolidated since the date of acquisition. Total acquisition consideration of $903 was paid in cash. The following assets were acquired at fair values: working capital of $28 and property, plant and equipment of $729. Goodwill amounting to $146 was recognized.

On November 9, 2011, Liberty Utilities (South) completed the acquisition of the water utility assets of KMB Utility Corporation ("KMB"). The acquisition has been accounted for using the acquisition method, with earnings from operations consolidated since the date of acquisition. Total acquisition consideration of $350 was paid in cash. The following assets were acquired at fair values: working capital of $43 and property, plant and equipment of $265. Goodwill amounting to $42 was recognized.

Both utilities are located in the state of Missouri.

(c) Agreement to Acquire New Hampshire Electric and Gas Utilities

On December 9, 2010, Liberty Utilities entered into agreements to acquire all issued and outstanding shares of Granite State Electric Company, a regulated electric utility, and EnergyNorth Natural Gas Inc. a regulated natural gas utility from National Grid USA ("National Grid") for total cash consideration of U.S. $285,000 plus working capital and subject to a final closing adjustment.

In connection with these acquisitions, Emera has agreed to a treasury subscription of subscription receipts convertible into 12,000,000 APUC common shares upon closing of the transactions at a purchase price of $5.00 per share. The receipt of cash from Emera and issuance of the shares is contingent on closing of these acquisitions and consequently the subscription receipts have not been recorded in the financial statements.

Closing of the transaction is subject to certain conditions including state and federal regulatory approval, and is expected to occur in 2012.

3. Acquisitions (continued)

(c) Agreement to Acquire New Hampshire Electric and Gas Utilities (continued)

The Company incurred $3,271 in total acquisition-related costs (2010 - $1,889); of which $1,382 were incurred during 2011. All such costs have been expensed in the consolidated Statement of Operations.

(d) Agreement to Acquire Mid-West Gas Utilities

On May 13, 2011, Liberty Utilities entered into an agreement with Atmos Energy Corporation ("Atmos Energy") to acquire certain regulated natural gas distribution utility assets (the "Mid-West Utilities") located in Missouri, Iowa, and Illinois. Total purchase price for the Mid-West Utilities is approximately U.S. $124,000, subject to certain working capital and other closing adjustments.

Closing of the transaction is subject to certain conditions including state and federal regulatory approval, and is expected to occur in 2012.

The Company incurred $398 in total acquisition-related costs during 2011 (2010 - $nil). All such costs have been expensed in the consolidated Statement of Operations.

(e) Agreement to Acquire Solar Energy Project

On November 27, 2011, APCo entered into agreements to acquire rights, subject to Ontario Power Authority approval, to develop a 10 MW-AC solar project located near Cornwall, Ontario which has been granted an Ontario Feed-in-Tariff contract by the Ontario Power Authority for a 20 year term at a rate of $443/MWh. The consideration for the power sale contract is $4,500 plus additional contingent consideration of $3,500 that is based on achieving certain construction milestones.

On December 30, 2011 Ontario Power Authority Approval was received and the transaction closed on January 4, 2012. Following the completion of all regulatory submissions and approvals, construction of the solar facility is expected to begin in the second half of 2012, with a commercial operation date estimated in early 2013.

(f) Power Purchase agreement for Chaplin Wind Project

Subsequent to the year end, APCo entered into a 25 year Power Purchase Agreement 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 25 year power purchase agreement features a rate escalation provision of 0.6% throughout the term of the agreement.

(g) Highground Capital Corporation

In 2008, the Company entered into an agreement with Highground Capital Corporation ("Highground") and CJIG Management Inc. ("CJIG) whereby, CJIG acquired all of the issued and outstanding common shares of Highground and the Company issued equity in the form trust units to the Highground shareholders and CJIG, in exchange for $26.2 million of cash and future consideration based on 50% of liquidation proceeds from sale of Highground's remaining assets by CJIG. During 2011, APUC received additional consideration of $1,073 (2010 - $170) from CJIG as APUC's share of additional proceeds. This has been recorded as an increase to share capital. As at December 31, 2011, further consideration from this transaction, if any, is not expected to be significant.

3. Acquisitions (continued)

(h) Acquisition of U.S. Wind Farms

On March 9, 2012, APCo entered into an agreement to acquire a 51% majority interest in a 480 MW portfolio of four wind projects in the United States from Gamesa Corporación Tecnológica, S.A. ("Gamesa") for total consideration of approximately U.S. $269 million. The portfolio will be acquired in two stages; closing of two existing wind farms is expected to occur promptly following receipt of regulatory approval and the acquisition of the remaining two wind farms following their respective commissionings near the end of 2012.

4. Accounts receivable

Accounts receivable as of December 31, 2011, include unbilled receivables of $11,304 (December 31, 2010 - $1,552) in the regulated utilities. The unbilled revenue is an estimate of the amount of utility revenue since the date the meters were last read.

5. Long-term investments and notes receivable

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

	2011	2010
32.4% of Class B non-voting shares of Kirkland Lake Power Corp.	$ 4,926	$ 8,197
25% of Class B non-voting shares of Cochrane Power Corporation	5,382	5,775
45% interest in the Algonquin Power (Rattle Brook) Partnership	3,784	3,790
50% interest in the Valley Power Partnership	1,676	1,845
Red Lily Subordinated loan, interest at 12.5% (b)	6,565	6,565
Red Lily Senior loan, interest at 6.31% (b)	13,000	6,100
Chapais Énergie, Société en Commandite 12.1% interest in Tranche A and Tranche B term loans The loans bear interest at the rate of 10.789% and 4.91%, respectively	2,913	3,329
Silverleaf resorts loan, interest at 15.48% (c)	2,056	2,010
Note Receivable - Twin Falls. The note bears interest at the rate of 6.75%	—	740
	40,302	38,351
Less: current portion	(482)	(1,172)
Total long term investments and notes receivable	$39,820	$37,179

The above notes are secured by the underlying assets of the respective facilities. There is no allowance for doubtful account in regards to the notes receivable as at December 31, 2011 and 2010.

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

(a) Red Lily I

The Red Lily I Partnership ('Partnership") is owned by an independent investor. The Company provides operation and supervision services to the Red Lily I project, a 26.4 megawatt wind energy facility located in south-eastern Saskatchewan.

The Company's investment in Red Lily I is in the form of participation in a portion of the senior debt facility, and a subordinated debt facility from the Partnership. APUC has advanced $13,000 (2010 - $6,100) under a senior debt facility to the Partnership. Another third party lender has also advanced $31,000 of senior debt to the Partnership. The Company's senior loan to the Partnership earns interest at the rate of 6.31% and will mature in 2016. Both tranches of senior debt are secured by substantially all the assets of the Partnership on a pari passu basis.

The subordinated loan earns an interest rate of 12.5%, the principal matures in 2036 but is repayable by the Partnership in whole or in part at any time after 2016, without a pre-payment premium. The subordinated loan is secured by substantially all the assets of the Partnership but is subordinated to the senior debt.

A second tranche of subordinated loan for an amount equal to the amounts outstanding on Tranche 2 of the senior debt but no greater than $17,000 will be advanced in 2016 by the Company. The proceeds from this additional subordinated debt are required to be used to repay Tranche 2 of the Partnership's senior debt, including APUC's portion.

In connection with the subordinated debt facility, the Company has been granted an option to subscribe for a 75% equity interest in the Partnership in exchange for the outstanding amount on its subordinated loan of up to $19,500, exercisable for a period of 90 days commencing in 2016. The fair value of the conversion option as at December 31, 2011 was determined to be negligible.

During the year ended December 31, 2011, APUC advanced $6,900 of the senior debt to the Partnership. As of December 31, 2011 APUC has funded a total of $13,000 (December 31, 2010 - $6,100) of the senior debt and $6,565 (December 31, 2010 - $6,565) of the subordinated debt.

(b) Silverleaf Resorts Inc – Hill County

On July 29, 2010, Liberty Water, a wholly owned subsidiary of APUC, made an investment in its Hill Country facility, a part of Silverleaf Resorts Inc.'s ("SRI") facilities in Comal County, Texas. The investment of $2,056 (U.S. $2,021) was made under an agreement with SRI to increase the capacity of a wastewater treatment facility to support the growth of the utility. This investment has been recorded in property, plant and equipment as additional capacity conveyed by SRI together with note receivable for funds advanced by APUC.

The note has a 10 year term and bears interest at 15.48%. The note is repayable in cash to the extent expansion does not form part of the rate base of the utility during the 10 year term. To the extent that the cost of the expansion becomes part of the rate base of the utility, the note will be assigned as payment to Silverleaf for the expansion costs with the excess received in cash.

6. Property, plant and equipment

Property, plant and equipment consist of the following:

2011

	Cost	Accumulated depreciation	Net book value
Generation			
Renewable	$ 527,922	$ 132,779	$395,143
Thermal	194,080	78,776	115,304
Distribution			
Water & wastewater	239,190	48,716	190,474
Electricity	154,154	2,636	151,518
Land	12,203	—	12,203
Equipment	50,823	23,429	27,394
Construction in progress	53,920	—	53,920
	$1,232,292	$ 286,336	$945,956

2010

	Cost	Accumulated depreciation	Net book value
Generation			
Renewable	$ 527,407	$ 114,780	$412,627
Thermal	191,138	69,816	121,322
Distribution			
Water & wastewater	219,744	41,840	177,904
Electricity	—	—	—
Land	11,976	—	11,976
Equipment	48,720	21,309	27,411
Construction in progress	10,500	—	10,500
	$1,009,485	$ 247,745	$761,740

Generation assets are those used to generate electricity. These assets include hydroelectric, wind and thermal generation stations, turbines, dams, reservoirs and other related equipment.

Electricity distribution assets are those used to distribute electricity within a specific geographic service territory to end users of electricity. These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment.

Water and waste water assets are those used to distribute water and collect wastewater. These assets include treating facilities and equipment, network of supply mains, pipes and canals, pumps and related generation equipment, meters, hydrants, collecting sewers and other related equipment.

Equipment assets include equipment, vehicles, inventory and information technology assets.

Renewable generation assets include cost of $94,606 (2010 - $94,606) and accumulated depreciation of $30,264 (2010 - $27,962) related to facilities under capital lease or owned by consolidated variable interest entities. Depreciation expense of facilities under capital lease was $2,302 (2010 - $2,536). Contributions received in aid of construction of $3,968 (2010 - $3,731) have been credited to the cost of the distribution assets. Water and wastewater distribution assets include expansion costs of $1,000 on which the Company does not currently earn a return.

6. Property, plant and equipment (continued)

Equipment includes cost of $4,227 (2010 - $4,402) and accumulated depreciation of $2,079 (2010 - $2,149) related to equipment under capital lease. Depreciation expense of equipment under capital lease was $282 (2010 - $292).

In December 2011, APCo wrote down its investment in a small hydro facility and recognized an impairment charge on property, plant and equipment of $1,370 (2010 - $1,836) representing the difference between the carrying value of the assets and their estimated fair value. The fair value of the facilities was estimated based on prior transactions involving sales of comparable facilities and management's best estimates. Subsequent to the year end the Company entered into an agreement to sell certain small hydro facilities located in the U.S for gross proceeds of $200. As a result, the Company wrote down its investment in these hydro facilities to fair value, less costs associated with the sale, and recognized a charge on property, plant and equipment of $662 (2010 - $656).

In December 2011, Liberty Utilities (South) wrote down $1,058 from facilities assets based on regulatory decisions in 2011 that these costs are not capitalizable for rate-base purposes.

7. Intangible assets

Intangible assets consist of the following:

2011

	Cost	Accumulated amortization	Net book value
Power sales contracts	$ 60,044	$ 20,548	$39,496
Customer relationships	19,235	3,462	15,773
Energy sales contract	—	—	—
	$ 79,279	$ 24,010	$55,269

2010

	Cost	Accumulated amortization	Net book value
Power sales contracts	$102,980	$ 45,345	$57,635
Customer relationships	18,811	2,912	15,899
Energy sales contract	4,228	3,876	352
	$126,019	$ 52,133	$73,886

Subsequent to the year end, the Region of Peel elected not to extend the existing waste processing contract with the Company and will instead seek competitive proposals from several waste management companies, including the Company. As a result, the remaining intangible assets associated with the existing waste management and energy contracts of the facility were written off in 2011 and the Company recognized a charge on intangible assets of $13,430.

Estimated amortization expense for intangibles for the next five years is $4,190 each year.

8. Regulatory assets and liabilities

The Company's regulated utility operating companies owned by Liberty Utilities are subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters. These utilities operate under cost-of-service regulation as administered by these state authorities. The Company's regulated utility operating companies are accounted for under the principles of U.S. Financial Accounting Standards Board ASC Topic 980 Regulated Operations ("ASC 980"). Under ASC 980, regulatory assets and liabilities that would not be recorded under U.S. GAAP for non-regulated entities are recorded to the extent that they represent probable future revenues or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate making process.

The utilities periodically file rate cases with their regulators. Rate cases seek to ensure that a particular facility has the opportunity to recover its operating costs and earn a fair and reasonable return on its capital investment as allowed by the regulatory authority under which the facility operates. Regulated 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 and deemed capital structure, together with all reasonable and prudent costs, establishes the revenue requirement upon which each utility's customer rates are determined.

Liberty Utilities monitors current and anticipated operating costs, capital investment and the rates of return in respect of each of its facility investments to determine the appropriate timing of a rate case filing in order to ensure it fully earns a rate of return on its investments. In the case of Liberty Utilities (West) and consistent with regulated utilities operating in California, the utility is required to make general rate case filings on a regular 3 year cycle. The utilities' most recent rate case was settled in 2009. The rate case was filed in February 2012 for the prospective years of 2012-2013. The regulator allows for the use of a prospective test year in the establishment of rates for the utility. The regulator also allows the use of annual adjuster mechanisms to account for inflation to labor and other expenses over the three year period of the rate case filing. In addition, a utility's rates include thresholds for capital expenditures, which once reached, can trigger adjustment mechanisms in between rate cases.

Energy Cost Adjustment Clause ("ECAC")

A portion of the revenue of Liberty Utilities (West) consists of ECAC which is designed to recoup or refund power supply costs that are caused by the fluctuations in the price of fuel and purchased power. The ECAC allowed in California mitigates the impact of changes in fuel prices and stabilizes earnings by allowing for the recovery of fuel and purchased power costs by updating rates charged on an annual basis. The mechanism consists of a base rate and amortization rate. The actual power supply costs incurred are tracked and compared to the base rate power supply costs to ensure the cumulative variance does not exceed 5%. In the event that the cumulative variance exceeds 5%, the ECAC allows Calpeco to request an adjustment to approved rates, reducing the commodity risk associated with the purchase of power.

The Post Test Year Adjustment Mechanism ("PTAM")

The PTAM allows Calpeco to update its rates annually by a cost inflation index. In addition, rates are allowed to be updated to recover the return on investment and associated depreciation of major capital projects.

8. Regulatory assets and liabilities (continued)

Power Purchase Agreement ("PPA")

Liberty Utilities (West) has entered into a five year all requirements PPA with NV Energy to provide its full electric needs at NV Energy's "system average cost" rates. The PPA had an effective starting date of January 1, 2011 with a five year renewal option. The PPA obligates NV Energy to use commercially reasonable efforts to supply Liberty Utilities (West) 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 resource adequacy ("RA") requirements, and are designed to enable Liberty Utilities (West) to comply with the associated RA reporting requirements. Liberty Utilities (West) accounts for the PPA as an operating lease. The costs associated with the PPA are recoverable through the ECAC.

Regulatory assets and liabilities consist of the following:

	December 31, 2011	December 31, 2010
Regulatory assets:		
Rate case costs (i)	$ 2,161	$ 2,164
Alternative revenue program (ii)	2,789	320
Water testing costs (iii)	79	—
Total regulatory assets	$ 5,029	$ 2,484
Less current regulatory assets	2,458	—
Non-current regulatory assets	$ 2,571	$ 2,484
Regulatory liabilities		
Deferred energy costs (iv)	$ 6,708	$ —
Cost of removal (v)	14,945	—
Total regulatory liabilities	$ 21,653	$ —
Less current regulatory liabilities	2,469	—
Non-current regulatory liabilities	$ 19,184	$ —

(i) Rate case

The costs to file, prosecute and defend rate case applications are referred to as rate case costs and are generally recoverable, in whole or in part, as part of the rate case process over a prescribed period of time. Deferred rate case costs are those rate case costs the utility expects to receive prospective recovery through its rates approved by the regulators. Under ASC 980 these costs are capitalized and amortized over the period of rate recovery granted by the regulator. The Company does not earn a return on these amounts but gets recovery of these costs in rates over the periods prescribed by the regulator.

8. Regulatory assets and liabilities (continued)

(ii) Alternative revenue program

A rate decision by the regulator of one of Liberty Utilities (South)'s utilities has ordered a phase-in of the rate increases it has granted wherein the full rate increase will be phased in over a 12 month period. The phase-in also includes a surcharge mechanism that ensures the utility is not disadvantaged by the phase in of the new rates.

(iii) Water testing costs

Water testing costs consist of certain expenses associated with some water testing costs ordered by the regulator. These costs are allowed to be recovered in rates in future periods. The regulatory asset associated with these costs is amortized over the period of rate recovery granted by the regulator. The Company does not earn a return on these amounts but gets recovery of these costs in rates over the periods prescribed by the regulator.

(iv) Deferred energy cost

Certain state statutes permit regulated utilities to adopt deferred energy accounting procedures. The intent of these procedures is to ease the effect on customers of fluctuations in the cost of purchased gas, fuel and purchased power.

Under deferred energy accounting, to the extent actual fuel and purchased power costs exceed fuel and purchased power costs recoverable through current rates that excess is not recorded as a current expense on the consolidated statement of operations but rather is deferred and recorded as a regulatory asset on the balance sheet in accordance with the provisions of ASC 980. Conversely, a regulatory liability is recorded to the extent fuel and purchased power costs recoverable through current rates exceed actual fuel and purchased power costs. These excess amounts are reflected in adjustments to rates and recorded as revenue or expense in future time periods, subject to regulatory review. The Utilities also record and are eligible under the statute to recover a carrying charge on such deferred balances.

(v) Cost of removal

The regulatory liability for cost of removal represents amounts that have been collected from ratepayers for costs that are expected to be incurred in the future to retire utility plant.

Future implications of discontinuing application of regulatory accounting

Liberty Utilities regularly assesses whether it can continue to apply regulatory accounting to its operations. In the event that the criteria no longer applied to a deregulated portion of the operations, the related regulatory assets and liabilities would be written off unless an appropriate regulatory mechanism is provided. Additionally, these factors could results in an impairment on utility assets.

8. Regulatory assets and liabilities (continued)

Income statement impact of applying regulatory accounting

If Liberty Utilities had not applied regulatory accounting earnings would have been affected as follows:

	December 31, 2011	December 31, 2010
Liberty Utilities (South):		
As a result of not recognizing the alternative revenue program in advance of the full rate increase being phased in rates, the rate case costs would have been expensed as incurred and revenue recognized would have been limited to the current phase of the phase-in plan.	$ (1,825)	$ (332)
Liberty Utilities (West):		
Recognizing over-recovered purchased power costs net of capitalized rate-case that would have been expensed.	4,106	—
Total increase (decrease) in earnings	$ 2,281	$ (332)

9. Long-term liabilities

Long term liabilities consist of the following:

	2011	2010
APCo		
Senior Unsecured Notes: $135,000 senior unsecured notes, interest rate of 5.5% maturing July 25, 2018. The notes are interest only, payable semi-annually in arrears, commencing January 25, 2012.	$134,778	$ —
Senior Secured Revolving Credit Facility: Revolving line of credit interest rate is equal to bankers acceptance or LIBOR plus a variable rate as outlined in the credit facility agreement. The current rate is LIBOR plus 2.5%.	—	64,500
Senior Debt Long Sault Rapids: Interest at rate of 10.2% repayable in blended monthly interest and principal installments of $402 and maturing December, 2027.	39,033	39,844
Sanger Bonds: U.S. $19,200 California Pollution Control Finance Authority Variable Rate Demand Resource Recovery Revenue Bonds Series 1990A, interest payable monthly, maturing September, 2020. The variable interest rate is determined by the remarketing agent. The effective interest rate for 2011 is 2.05% (2010 – 1.33%).	19,526	19,096
Senior Debt Chute Ford: Interest rate of 11.6% repayable in blended monthly interest and principal installments of $64 and maturing April, 2020.	4,072	4,350
AirSource Senior Debt Financing: Interest rate is equal to bankers' acceptance plus 1% and matured on October 31, 2011. Monthly interest and quarterly principal payments totaled $72,146 (2010 - $1,741). The effective rate of interest for 2011 was 1.38% (2010 – 1.81%).	—	68,789
Bonds Payable: Obligation to the City of Sanger (2010 - U.S. $230).	—	229
Liberty Utilities		
Senior Notes – California Pacific Electric Company, LLLC: U.S. $45,000 senior unsecured notes, interest rate of 5.19%, maturing December 29, 2020 and U.S. $25,000, interest rate of 5.59%, maturing December 29, 2025. The notes are interest only, payable semi-annually.	71,190	—

9. Long term liabilities (continued)

	2011	2010
Senior Unsecured Notes – Liberty Water Co:		
U.S. $50,000 senior unsecured notes, interest rate of 5.6% maturing December 22, 2020. The notes are interest only, payable semi-annually, until June 20, 2016 with semi-annual interest payments and an annual principal repayment of U.S. $5,000 thereafter.	50,850	49,730
Litchfield Park Service Company Bonds:		
1999 and 2001 IDA Bonds. Interest rates of 5.95% and 6.75% repayable in blended semi-annual installments maturing October 2023 and October 2031. Principal payments of U.S. $270 (2010 – U.S. $255). The balance of these notes at December 31, 2011 was U.S. $3,605 and U.S. $7,100, respectively (2010 – U.S. $3,810 and U.S. $7,165).	11,868	11,931
Bella Vista Water Loans:		
Water Infrastructure Financing Authority of Arizona Interest rates of 6.26% and 6.10% repayable in monthly and quarterly installments (U.S. $15 and U.S. $4) maturing March, 2020 and December, 2017. The balance of these notes at December 31, 2011 was US$1,275 and US$83 respectively (2010 – US$1,384 and US$95)	1,399	1,489
	$332,716	$259,958
Less: current portion	(1,624)	(70,490)
	$331,092	$189,468

Certain long-term debt issued at a subsidiary level relating to a specific operating facility is secured by the respective facility with no other recourse to APUC, APCo or Liberty Utilities. The loans have certain financial covenants, which must be maintained on a quarterly basis. Non compliance with the covenants could restrict cash distributions/dividends to Liberty Utilities, APCo and APUC from the specific facilities.

APCo

On July 25, 2011 APCo completed a $135,000 private placement debt financing commitment at a price of $998.28 per $1,000 principal amount of debenture. The notes are senior unsecured with a seven year maturity date of July 25, 2018 and bear interest at 5.5%. The notes are interest only, payable semi-annually in arrears, commencing January 25, 2012. APCo incurred deferred financing costs of $1,685, which are being amortized to interest expense over the term of the loan using the effective interest rate method. The net proceeds of this financing were used to retire the project debt related to the St. Leon facility (Air Source Senior Debt Financing) and to reduce amounts outstanding on APCo's senior secured revolving credit facility. As of December 31, 2011, the Company had accrued $3,255 in interest payable.

9. Long term liabilities (continued)

In February 2011, APCo renewed its senior secured revolving credit facility in the maximum amount of $142,000 (the "Facility") for a three year term with its Canadian bank syndicate. The Facility now has a maturity date of February 14, 2014. Refinancing costs and fees related to the renewal of $1,446 have been recorded as deferred financing costs in the period. On July 25, 2011, in conjunction with the APCo debenture offering discussed above, the maximum availability on the senior revolving facility was reduced to $120,000. At December 31, 2011, $0 (2010 - $64,500) has been drawn on the Facility. In addition, the availability of the revolving credit facility has been reduced for certain outstanding letters of credit in amounts totaling $39,606 (2010 - $33,122).

Therefore, APCo had $80,394 of undrawn bank facilities as at December 31, 2011. The terms of the Facility contain certain financial covenants including debt service ratios and leverage ratios which can limit the amounts available for borrowing. Based on current covenants at December 31, 2011, APCo is able to access the entire undrawn amount of the Facility. The facility is secured by a fixed and floating charge over all APCo entities.

On December 22, 2010 APUC's subsidiary, Liberty Water Co. ("Liberty Water"), issued U.S. $50,000 senior unsecured notes with a ten year maturity date of December 2020 and bearing interest at 5.6%. The notes are interest only, payable semi-annually, until June 20, 2016 with semi-annual interest payments and annual principal repayments of U.S. $5,000 thereafter. As of December 31, 2011, Liberty Water incurred deferred financing costs of $1,235 (2010 - $854) which are being amortized to interest expense over the term of the loan using the effective interest rate method.

APUC's subsidiary California Pacific Electric Company, LLC has issued U.S.$70,000 senior unsecured notes consisting of U.S. $45,000 bearing an interest rate of 5.19% maturing December 29, 2020 and U.S. $25,000 bearing an interest rate of 5.59% maturing December 29, 2025. The notes are interest only, payable semi-annually. Financing costs of $ 1,048 (2010 - $1,069) incurred with respect to this placement have been recorded in deferred financing costs.

Subsequent to year-end, on January 19, 2012, Liberty Utilities Co. entered into an agreement for a U.S. $80,000 senior unsecured revolving credit facility with a three year term at an interest rate equal to LIBOR plus a variable rate as outlined in the credit facility agreement. The current rate is LIBOR plus 1.75%.

Interest paid on the long-term liabilities was $18,089 (2010 - $9,064).

9. Long term liabilities (continued)

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

	2012	2013	2014	2015	2016	Thereafter	Total
APCo							
Senior Unsecured	$ —	$ —	$ —	$ —	$ —	$134,778	$134,778
Senior Debt Long Sault Rapids	897	993	1,094	1,211	1,340	33,498	39,033
Sanger Bonds	—	—	—	—	—	19,526	19,526
Senior Debt Chuteford	309	346	389	436	489	2,103	4,072
Liberty Utilities							
Senior Unsecured	—	—	—	—	5,085	45,765	50,850
Senior Unsecured	—	—	—	—	—	71,190	71,190
Litchfield Park Service Company Bonds	290	305	326	346	366	10,235	11,868
Bella Vista Water Loans	128	136	135	144	140	716	1,399
Total	$1,624	$1,780	$1,944	$2,137	$7,420	$317,811	$332,716

10. Convertible Debentures

2011	Series 1A	Series 2A	Series 3	Total
Maturity date	2014 November 30	2016 November 30	2017 June 30	
Interest rate	7.50%	6.35%	7.00%	
Conversion price per share	$ 4.08	$ 6.00	$ 4.20	
Carrying value at December 31, 2010	$ 59,156	$ 59,699	$62,905	$181,760
Conversion to shares (Note12), net of costs	(59,449)	(10)	(334)	(59,793)
Amortization and accretion	293	37	—	330
Carrying value at December 31, 2011	$ —	$ 59,726	$62,571	$122,297
Face value at December 31, 2011	$ —	$ 59,957	$62,571	$122,528

2010	Series 1A	Series 2A	Series 3	Total
Maturity date	2014 November 30	2016 November 30	2017 June 30	
Interest rate	7.50%	6.35%	7.00%	
Conversion price per share	$ 4.08	$ 6.00	$ 4.20	
Carrying value at December 31, 2009	$ 62,686	$ 59,664	$63,250	$185,600
Conversion to shares (Note 12), net of costs	(4,473)	—	(345)	(4,818)
Amortization and accretion	943	35	—	978
Carrying value at December 31, 2010	$ 59,156	$ 59,699	$62,905	$181,760
Face value at December 31, 2010	$ 62,470	$ 59,967	$62,905	$185,342

Subsequent to year-end, the remaining principal amount of $59,967 of Series 2A Debentures were redeemed and converted into 10,322,518 shares of APUC (note 12).

10. Convertible Debentures (continued)

The Series 3 debentures are convertible into common shares of APUC at the option of the holder at a conversion price of $4.20 per common share, being a ratio of approximately 238.1 common shares per $1,000 principal amount of debentures. The debentures cannot be redeemed by APUC on or before December 31, 2012. During the period of January 1, 2013 until December 31, 2014, the Series 3 debentures may be redeemed by APUC provided that the weighted-average trading price of the underlying share price on the TSX for the 20 consecutive trading days is equal to or exceeds a price of $5.25 (125% of the conversion price of $4.20). During the period of January 1, 2015 until the Series 3 debentures' maturity, APUC can redeem the Series 3 debentures for 100% of the face value of the Series 3 Debentures with cash, or for 105% of the face value of the Series 3 debentures with additional shares.

11. Other long-term liabilities

Other long term liabilities consist of the following:

	2011	2010
Contingent consideration	$ 1,080	$ 1,198
Deferred water rights inducement	2,927	3,008
Customer deposits	2,483	1,985
Capital Leases		
Obligation for equipment leases. Interest rates varying from 1.90% to 5.80%, monthly interest and principal payments with varying dates of maturity from March 2012 to December 2014	501	535
Other	5,073	5,099
	12,064	11,825
Less: current portion	(1,641)	(1,011)
	$10,423	$10,814

12. Shareholders' Capital

Number of common shares:

	2011	2010
Common shares, beginning of period	95,422,778	93,064,120
Conversion and redemption of convertible debentures	15,300,824	1,178,478
Issuance pursuant to management internalization	—	1,180,180
Issuance of shares	25,399,178	—
Common shares, end of period	136,122,780	95,422,778

12. Shareholders' Capital (continued)

Authorized

APUC is authorized to issue an unlimited number of common shares. The holders of the common shares are entitled to dividends if, as and when declared by the Board of Directors (the Board); to one vote per share at meetings of the holders of common shares; and upon liquidation, dissolution or winding up of APUC to receive pro rata the remaining property and assets of APUC; subject to the rights of any shares having priority over the common shares, of which none are authorized or outstanding.

APUC is authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board of Directors of APUC. As at December 31, 2011, APUC does not have any issued and outstanding preferred shares.

On June 29, 2010, the Company issued 1,180,180 shares valued at $4,763 pursuant to the Management Internalization Agreement signed on December 21, 2009. The issuance of shares and final settlement was approved by the Company's shareholders at its annual general meeting held on June 23, 2010.

In 2010, $4,473 principal amount of New Series 1 Debentures were converted at the option of the holders at a price of $4.08 for each share into 1,096,336 shares of APUC. The carrying amount of these debentures net of unamortized issuance costs and the bifurcated equity component totaling $4,094 has been recorded as share capital.

In 2010, $345 principal amount of Series 3 Debentures were converted at the option of the holders at a price of $4.20 for each share into 82,142 shares of APUC. The carrying amount of these debentures net of unamortized issuance costs and the bifurcated equity component totaling $311 has been recorded as share capital.

On April 1, 2011, APUC called for the redemption of the Series 1A Debentures on May 16, 2011 ("Redemption Date"). Prior to the Redemption Date, a principal amount of $60,339 of Series 1A Debentures were converted into 14,788,975 shares of APUC. On May 16, 2011, APUC redeemed the remaining Series 1A Debentures by issuing and delivering 430,666 APUC shares. On December 31, 2011, as a result of the Redemption there were no Series 1A Debentures outstanding.

During the year ended December 31, 2011, $10 principal amount of Series 2A Debentures were converted at the option of the holders at a price of $6.00 for each share into 1,666 shares of APUC.

During the year ended December 31, 2011, $334 principal amount of Series 3 Debentures were converted at the option of the holders at a price of $4.20 for each share into 79,517 shares of APUC.

Subsequent to year-end, the remaining principal amount of $59,967 of Series 2A Debentures were redeemed and converted into 10,322,518 shares of APUC.

Subsequent to the year end, $66 principal amount of Series 3 Debentures were converted at the option of the holders into 15,711 shares of APUC.

12. Shareholders' Capital (continued)

Shareholders' Rights Plan

On June 23, 2010, the Company's shareholders adopted a shareholders' rights plan (the "Rights Plan"). The Rights Plan has an initial term of three years. Under the Rights Plan, one right is issued with each issued share of the Company. The rights remain attached to the shares and are not exercisable or separable unless one or more certain specified events occur. If a person or group acting in concert acquires 20 percent or more of the outstanding shares (subject to certain exceptions) of the Company, the rights will entitle the holders thereof (other than the acquiring person or group) to purchase shares at a 50 percent discount from the then current market price. The rights provided under the Rights Plan are not triggered by any person making a "Permitted Bid", as defined in the Rights Plan.

Dividend reinvestment plan

The Company has a Common Shareholder Dividend Reinvestment Plan, which provides an opportunity for shareholders to reinvest dividends for the purpose of purchasing common shares. Additional Common Shares acquired through the reinvestment of cash dividends will be purchased in the open market or will be issued by APUC at a discount of up to 5% from the average market price, all as determined by the Company from time to time.

Employee Share Purchase Plan

In September 2011, the Company approved an employee share purchase plan ("ESPP") which commenced in October 2011. Eligible employees may have a portion of their earnings withheld to be used to purchase the Company's common shares. The Company will match a) 20% of employee contribution amount for the first five thousand dollars per employee contributed annually and 10% of employee contribution amount for contributions over five thousand dollars up to ten thousand dollars annually, for Canadian employees, and b) 15% of employee contribution amount for the first fifteen thousand dollar per employee contributed annually, for U.S. employees. Shares purchased through the Company match portion shall not be eligible for sale by the participant for a period of one year following the contribution date on which such shares were acquired. At the Company's option, the shares may be (i) issued to participants from treasury at the average share price or (ii) acquired on behalf of participants by purchases through the facilities of the TSX by an independent broker. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares.

The Company uses the fair value based method to measure the compensation expense related to the Company's contribution. For the year ended December 31, 2011, a total of 7,176 common shares were issued to employees under the ESPP plan for a total compensation expense related to the ESPP in 2011 of $9.

12. Shareholders' Capital (continued)

Stock Option Plan

During 2010, the Company's shareholders approved a stock option plan (the "Plan") that permits the grant of share options to key officers, directors, employees and selected service providers. The aggregate number of shares that may be reserved for issuance under the Plan must not exceed 10% of the number of Shares outstanding at the time the options are granted. The number of shares subject to each option, the option price, the expiration date, the vesting and other terms and conditions relating to each option shall be determined by the Board from time to time. Dividends on the underlying shares do not accumulate during the vesting period. Option holders may elect to surrender any portion of the vested options which is then exercisable in exchange for the In-the-Money Amount. In accordance with the Plan, the In-The-Money Amount represents the excess, if any, of the market price of a share at such time over the option price, in each case such In-the-Money amount being payable by the Company in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards.

In the case of qualified retirement, the Board may accelerate the vesting of the unvested options then held by the optionee at the Board's discretion. All vested options may be exercised within ninety days after retirement. In the case of death, the options vest immediately and the period over which the options can be exercised is one year. In the case of disability, options continue to vest and be exercisable in accordance with the terms of the grant and the provisions of the plan. Employees have up to thirty days to exercise vested options upon resignation or termination.

The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date. The Company determines the fair value of options granted using the Black-Scholes option-pricing model. The risk-free interest rate is based on the zero-coupon Canada Government bond with a similar term to the expected life of the options at the grant date. Expected volatility was estimated based on the adjusted historic volatility of the Company's shares. The expected life was estimated to equal the contractual life of the options. The dividend yield rate was based upon recent historical dividends paid on APUC shares.

The following assumptions were used in determining the fair value of share options granted:

	2011	2010
Risk-free interest rate	3.0%	2.9%
Expected volatility	30%	29%
Expected dividend yield	5.3%	5.9%
Expected life	8 years	8 years
Weighted average grant date fair value per option	$ 0.99	$ 0.61

12. Shareholders' Capital (continued)

Stock option activity during the period is as follows:

	Number of shares	Weighted average exercise price	Weighted average remaining contractual term	Aggregate intrinsic value
Balance at January 1, 2011	1,160,204	$ 4.05	7.62	$ 1,056
Granted	1,326,900	5.38	8.00	22
Balance at December 31, 2011	2,487,104	$ 4.76	6.96	$ 4,134
Exercisable at December 31, 2010	386,735	$ 4.05	6.62	$ 917

On March 14, 2012, 1,194,606 stock options were granted to senior executives of APUC which allow for the purchase of common shares at a price of $6.22.

Directors Deferred Share Units

In June 2011, the Shareholders approved a Deferred Share Unit Plan. Under the plan, non-employee directors of the Company may elect annually to receive all or any portion of their compensation in Deferred Share Units ("DSUs") in lieu of cash compensation. Directors' fees are paid on a quarterly basis and at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one of the Company's common share. Dividends accumulate in the DSU account and are converted to DSUs based on the market value of the shares on that date. DSUs cannot be redeemed until the Director retires, resigns, or otherwise leaves the Board. The DSUs provide for settlement in cash or shares at the election of the Company. As the Company expects to settle these instruments in cash, these DSUs are accounted for as liability awards and dividends accumulated are recognized as additional compensation cost. The DSU liabilities are marked-to-market at the end of each period based on the common share price at the end of the period. As at December 31, 2011, no DSUs had been issued.

12. Shareholders' Capital (continued)

Performance Share Units

The Company approved a performance share unit plan to its employees as part of the Company's long-term incentive program. Performance share units ("PSUs") are granted annually for three-year overlapping performance cycles. PSUs vest at the end of the three-year cycle and will be calculated based on established performance criteria. At the end of the three-year performance periods, the number of shares issued can range from 0% to 144% of the number of PSUs granted. Dividends accumulating during the vesting period are converted to PSUs based on the market value of the shares on that date and are recorded in equity as the dividend's are declared. None of these PSUs have voting rights. Any PSUs not vested at the end of a performance period will expire. The PSUs provide for settlement in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these PSUs will be accounted for as equity awards. Compensation expense associated with PSUs is recognized ratably over the performance period based on the Company'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

A summary of the PSUs activity follows:

	Employees PSUs Outstanding
December 31, 2010	—
Granted	21,123
December 31, 2011	21,123

A summary of the non-vested PSUs follows:

	Employees PSUs	
	Shares	Weighted Average Grant-Date Fair Value
Non-vested at January 1, 2011	—	$ —
Granted	21,123	5.62
Non-vested at December 31, 2011	21,123	$ 5.62

Share-based compensation

For the year ended December 31, 2011, APUC recorded $769 (2010 - $108) in total share-based compensation expense. No tax deduction was realized in the current year. The compensation expense is recorded as part of the operating expenses in the Consolidated Statement of Operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at December 31, 2011, total unrecognized compensation costs related to non-vested options and share unit awards were $1,216 and $70 respectively, which are expected to be recognized over a period of 1.76 years and 2 years respectively.

13. Cash dividends

All dividends of the Company are made on a discretionary basis as determined by the Board of the Company. For the year ended December 31, 2011, the Company declared cash dividends to shareholders totaling $32,426 (2010 - $22,765) or $0.24 per common share (2010 - $0.24 per common share).

On November 14, 2011, the Board declared a dividend on the Company's shares of $0.07 per share payable on January 16, 2012 to the shareholders of record on December 30, 2011 for the period from October 1, 2011 to December 31, 2011.

14. Income Taxes

The provision for income taxes in the consolidated statements of operations represents an effective tax rate different than the Canadian enacted statutory rate of 28.25% (2010 - 31%). The differences are as follows:

	2011	2010
Expected income tax expense / (recovery) at Canadian statutory rate	$ 1,204	$ (45)
Increase (decrease) resulting from:		
Recognition of deferred credit	(6,581)	(6,636)
Differences in tax rates in subsidiaries and changes in tax Rates	(861)	(202)
Change in valuation allowances	(16,834)	(5,979)
Foreign exchange on intercompany items	2,250	(6,228)
Non-taxable corporate dividend	(1,418)	(1,191)
Non-controlling interests share of income	(1,317)	—
Other permanent difference	518	(510)
Income tax recovery	$(23,039)	$(20,791)

For the years ended December 31, 2011 and 2010, income/(loss) before taxes consists of the following:

	2011	2010
Canadian operations	$(5,242)	$(6,405)
U.S. operations	9,505	4,007
	$ 4,263	$(2,398)

14. Income Taxes (continued)

As a result of the business combination transaction in 2009, APUC recorded certain additional tax attributes. These tax attributes have been recognized to the extent management believes they are more likely than not to be realized. The excess of the carrying amount of the tax attributes recorded over the consideration was reflected as a deferred credit of $55,647 on the transaction date. The deferred credit is being recognized in income as a deferred income tax recovery in relative proportion to the amount of the related deferred tax assets that are utilized in the period.

Income tax expense (recovery) attributable to income/(loss) consists of:

	Current	Deferred	Total
Year ended December 31, 2011			
Canada	$ 268	$ (1,936)	$ (1,668)
United States	32	(21,403)	(21,371)
	$ 300	$(23,339)	$(23,039)
Year ended December 31, 2010			
Canada	200	(1,081)	(881)
United States	(269)	(19,641)	(19,910)
	$ (69)	$(20,722)	$(20,791)

The tax effect of temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2011 and 2010 are presented below:

	2011	2010
Deferred income tax assets:		
Non-capital loss, investment tax credits, currently non-deductible interest expenses, and financing costs	$ 133,625	$ 120,973
Unrealized foreign exchange difference on intercompany notes	—	17,860
Customer advances in aid of construction	6,610	5,559
Regulatory liabilities	4,313	—
Foreign exchange hedges and interest rate swaps	2,233	1,459
Total deferred income tax assets	146,781	145,851
Less: Valuation allowance	(15,063)	(31,896)
Total deferred income tax assets	131,718	113,955
Deferred tax liabilities:		
Property, plant and equipment	(96,158)	(96,554)
Intangible assets	(7,812)	(7,639)
Other	(1,009)	(1,697)
Total deferred income tax liabilities	(104,979)	(105,890)
Net deferred income tax assets	$ 26,739	$ 8,065

14. Income taxes (continued)

The valuation allowance for deferred tax assets as of December 31, 2011 and 2010 was $15,062 and $31,896, respectively. The net change in the total valuation allowance was a decrease of $16,834 in 2011 and a decrease of $5,979 in 2010. The valuation allowance at December 31, 2011 was primarily related to operating losses that, in the judgment of management, are not more likely than not to be realized. In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities (including the impact of available carry back and carry forward periods), projected deferred taxable income, and tax-planning strategies in making this assessment.

Deferred income taxes are classified in the financial statements as:

	2011	2010
Current deferred income tax asset	$ 13,022	$ 14,015
Non-current deferred income tax asset	67,671	74,006
Current deferred income tax liability	(723)	(514)
Non-current deferred income tax liability	(53,231)	(79,442)
	$ 26,739	$ 8,065

As at December 31, 2011, the Company had non-capital losses carry forwards available to reduce future year's taxable income, which expire as follows:

Year of expiry	Non-capital losses carry forwards
2015	$ 28,406
2026 and onwards	239,823
	$ 268,229

15. Related party transactions

Certain executives of APUC are shareholders of Algonquin Power Management Inc. ("APMI"), the former manager of APCo. A member of the Board of Directors of APUC is an executive at Emera.

APUC has leased its head office facilities since 2001 from an entity owned by the shareholders of APMI on a triple net basis. Base lease costs for year ended December 31, 2011 were $327 (2010 - $327).

APUC utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI, Algonquin Airlink Inc. In 2004, APUC entered into an agreement and remitted $1,300 to the affiliate as an advance against expense reimbursements (including engine utilization reserves) for APUC's business use of the aircraft. Under the terms of this arrangement, APUC has priority access to make use of the aircraft for a specified number of hours at a cost equal solely to the third party direct operating costs incurred when flying the aircraft. During the year, APUC incurred costs in connection with the use of the aircraft of $453 (2010 - $430) and amortization expense related to the advance against expense reimbursements of $274 (2010 - $112). At December 31, 2011, the remaining amount of the advance was $279 (2010 - $554) and is recorded in other assets.

15. Related party transactions (continued)

Affiliates of APMI hold 60% of the outstanding Class B limited partnership units issued by the St. Leon Wind Energy LP ("St. Leon LP"), a subsidiary of APUC and the legal owner of the St. Leon facility. The holders of the Class B Units are entitled to 2.5% of the income allocations and cash distributions from St. Leon LP for a 5 year period commencing June 17, 2008, increasing by 2.5% every 5 years to a maximum of 10% by year 15. In any particular period, cash distributions to the holders of the Class B Units are only to be made after distributions have been made to the other partners, in an aggregate amount, equal to the debt service on the outstanding debt in respect of such period. The related holders of the Class B units received cash distributions of $314 for the year ended December 31, 2011 (2010 - $266). APUC and the Class B holders have executed an agreement which outlines the relationship of the parties in relation to the St. Leon II expansion of the St Leon facility ("Expansion Agreement"). The terms of the Expansion Agreement allow APUC to expand the St Leon project on a "no-net-harm-basis" to the Class B holders and provide APUC with the full economic benefit of such expansion.

APMI is one of the two original developers of Red Lily I (note 5(b)) and both developers are entitled to a royalty fee based on a percentage of operating revenue and a development fee from the equity owner of Red Lily I. The royalty fee is initially equal to 0.75% of gross energy revenue, increasing every five years up to 2% after twenty-five years. During the year, APUC acquired APMI's interest in this royalty for an amount of $600. This amount has been recorded as a purchase of intangible assets and the amount owing to APMI is included in accrued liabilities at December 31, 2011.

Staff managed by APUC have historically operated an additional three hydroelectric generating facilities not owned by APUC where Senior Executives hold an equity interest. Effective January 1, 2011, management of these facilities is now being undertaken by Algonquin Power Systems Inc. ("APS") which is an entity where Senior Executives hold equity interests. APUC and APS agreed to provide some transition services to each other until December 31, 2011. Costs for providing such transition services are intended to be on a cost recovery basis with no mark-up.

As at December 31, 2011, included in amounts due from related parties is $663 (2010 - $718) owed to APUC from APMI and included in amounts due to related parties is $1,795 (2010 - $901) owed to APMI. These amounts arise from the transactions described above.

A contract with a subsidiary of Emera to purchase energy on Independent System Operator New England ("ISO NE") and provide scheduling services on ISO NE was included as part of the acquisition of the Energy Services Business associated with the Tinker Acquisition. The contract expired March 31, 2010 and was not renewed. As a result of this contract, during 2010 a subsidiary of Emera provided services to and purchased energy on ISO NE on behalf of the Energy Services Business. In this capacity, APUC paid a subsidiary of Emera an amount of $0 (2010 - $1,368) which was included as an operating expense on the consolidated statement of operations.

In 2010, APUC entered into a one year contract with a subsidiary of Emera to provide lead market participant services for fuel capacity and forward reserve markets in ISO NE for the Windsor Locks facility. During 2011 APUC paid U.S. $260 (2010 - $196) in relation to this contract. In the same period, APUC provided a corporate guarantee to a subsidiary of Emera in an amount of U.S. $1,000 in conjunction with this contract.

On December 21, 2010, a subsidiary of Emera acquired Maine & Maritimes Corporation, the parent company of Maine Public Service Company ("MPS"). For 2011, the Energy Services Business sold electricity amounting to $6,564 (2010 - $0). In the same period, APUC provided a corporate guarantee to MPS in an amount of U.S. $3,000 and a letter of credit in an amount of U.S $100, primarily in conjunction with a three year contract to provide standard offer service to commercial and industrial customers in Northern Maine.

15. Related party transactions (continued)

As of December 31, 2011, included in amounts due from related parties is $1,612 (2010 - $0) owed from Emera related to the unpaid contribution of their share of Liberty Energy (California) costs.

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 after tax equity cash flows commencing in 2014.

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

Subsequent to December 31, 2011, APUC and the Parties reached an Agreement to resolve a number of the historic joint business associations between APUC and the Parties. The transaction is subject to finalization of definitive agreements which are expected to be completed in the second quarter of 2012.

Under this term sheet, it is proposed that 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 Sanger repowering project, the acquisition of the Clean Power Income Fund and the development of the Red Lily I wind project. The Company is currently evaluating the impact the settlement will have on the consolidated financial statements.

16. Interest, dividend and other income

Interest, dividend and other income includes the following items:

	2011	2010
Interest income	$2,533	$1,138
Dividend income	2,928	2,928
Equity income	193	431
Other	5	667
	$5,659	$5,164

17. Other revenue

Other revenue consists of the following:

	2011	2010
Hydro mulch sales	$1,352	$1,318
Red Lily development fees	209	209
Red Lily royalty income and supervisory fees	947	—
Red Lily construction services fees and natural gas sales	757	1,804
Gain on sale of assets	358	—
Other	20	—
	$3,643	$3,331

18. Commitments and Contingencies

Land and Water Lease Commitments:

Certain of the Company's operating entities have entered into agreements to lease either land, water rights or both that are used in the generation of electricity or to pay, in lieu of property tax, an amount based on electricity production. The terms of these leases have varying maturity dates that continue up to 2048. These payments typically have a fixed and variable component. The variable fee is generally linked to actual power production or gross revenue. APUC incurred costs of $2,654 during 2011 (2010 - $2,231) in respect of these agreements for all of its operating entities.

Contingencies:

APUC and its subsidiaries are involved in various claims and litigation arising out of the ordinary course and conduct of its business. Although such matters cannot be predicted with certainty, management does not consider APUC's exposure to such litigation to be material to these financial statements. Accruals for any contingencies related to these items are recorded in the financial statements at the time it is concluded that its occurrence is probable and the related liability is estimable.

On December 19, 1996, the Attorney General of Québec ("Québec AG") filed a suit in Québec Superior Court against a subsidiary of APUC claiming for amounts that the APUC subsidiary has been paying to The St. Lawrence Seaway Management Corporation (the "Seaway Management") under its water lease with Seaway Management. The water lease contains a "hold harmless" clause which mitigates this claim. As such, the APUC subsidiary brought the Attorney General of Canada and Seaway Management (the "Federal Authorities") into the proceedings in an action in warranty. On March 27, 2009, the Superior Court dismissed the claim of the Québec AG and suspended the action in warranty following final judgment in this case.

The Québec AG subsequently appealed this decision and on October 21, 2011 the Québec Court of Appeal allowed the appeal and condemned the APUC subsidiary to pay approximately $5.4 million which includes the amount claimed with interest.

The APUC subsidiary believes it is held harmless in its water lease from this decision. The Federal Authorities have decided not to appeal this decision to the Supreme Court of Canada. APUC and Seaway Management are now required to go back to the Superior Court of Quebec which will determine the amount of money reimbursable by Seaway Management to APUC pursuant to the terms of the Water Lease. As a result, the probability of loss, if any, and its quantification cannot be estimated at this time but could range from $nil to $5.4 million. Accordingly, no accruals for amounts owed or recoverable in respect of the water lease dues already paid to Seaway Management have been recorded in the financial statements. Conversely, the Company accrued $1,000 of water lease owed to Québec AG for the years 2008 to 2011, which years are subsequent to those covered by the Court Decision and might not be subject to the legal right of offset. Probable amounts recoverable from the Federal Authorities of $300 related to these years were also recorded in 2011.

18. Commitments and Contingencies (continued)

Other Commitments:

In addition to the commitments related to the proposed acquisitions disclosed in note 3 the following significant commitments exist at December 31, 2011.

Legislation in the Province of Quebec requires technical assessments be made of all dams within the province and remediation of any technical deficiencies identified in accordance with the assessment. APUC is in the process of conducting the assessments as required. Based on assessments to date, some of which are preliminary, APUC has estimated the remaining potential remedial measures involving capital expenditures to be approximately $16,900 which may be required to comply with the legislation and which would be invested over a five year period or longer.

APUC has outstanding purchase commitments for long-term service agreements, capital project commitments and operating leases. Detailed below are estimates of future commitments under these arrangements:

	2012	2013	2014	2015	2016	Thereafter	Total
Long term service agreements	$ 4,559	$ 4,072	$ 4,153	$ 4,236	$ 4,321	$73,008	$ 94,349
Purchased power	45,053	45,155	46,375	45,867	45,053	—	227,503
Capital projects	7,871	—	—	—	—	—	7,871
Operating leases	939	609	369	282	20	—	2,219
Total	**$58,422**	**$49,836**	**$50,897**	**$50,385**	**$49,394**	**$73,008**	**$331,942**

Liberty Utilities (West) has entered into a five year all-purpose PPA with NV Energy to provide its full electric requirements at NV Energy's "system average cost" rates. The PPA has an effective starting date of January 1, 2011 with a five year renewal option. The commitment amounts included in the table above are based on market prices as of December 31, 2011. However, the effects of purchased power unit cost adjustments are mitigated through a purchased power rate-adjustment mechanism.

19. Basic and diluted net earnings per share

Basic and diluted earnings per share have been calculated on the basis of net earnings attributable to the Company and the weighted average number of shares outstanding during the year. Diluted net income per share is computed using the weighted-average number of common shares and, if dilutive, potential common shares outstanding during the period. Potential common shares consist of the incremental common shares issuable upon the exercise of stock options, PSUs, DSUs, shareholders' rights and convertible debentures. The dilutive effect of outstanding stock options, PSUs, DSUs and shareholders' rights is reflected in diluted earnings per share by application of the treasury stock method while the dilutive effect of convertible debentures is reflected in diluted earnings per share by application of the as if converted method. The weighted average shares outstanding during the year are as follows:

	2011	2010
Weighted average shares – basic	116,712,934	94,338,193
Dilutive effect of share-based awards	249,854	—
Weighted average shares – diluted	116,962,788	94,338,193

The shares potentially issuable as a result of the convertible debentures and 1,326,900 stock options (2010 –1,160,204) are excluded from this calculation as they are anti-dilutive.

20. Non-cash operating items

The changes in non-cash operating items is comprised of the following:

	2011	2010
Accounts receivable	$(11,674)	$(6,817)
Related party balances	145	—
Supplies and consumable inventory	(1,087)	—
Income tax receivable	(133)	1,143
Prepaid expenses	(2,071)	1,153
Accounts payable	3,991	5,050
Accrued liabilities	9,010	—
Current income tax liability	207	195
Net regulatory assets and liabilities	70	(809)
	$ (1,542)	$ (85)

21. Segmented Information

APUC has two operating segments: APCo which owns or has interests in renewable energy facilities and thermal energy facilities and Liberty Utilities which owns and operates utilities in the United States of America providing water, wastewater and local electric distribution services.

Within APCo there are three divisions: Renewable Energy, Thermal Energy and Development. The Renewable Energy division operates the Company's hydro-electric and wind power facilities. The Thermal Energy division operates co-generation, energy from waste, steam production and other thermal facilities. The Development division develops the Company's greenfield power generation projects as well as any expansion of the Company's existing portfolio of renewable energy and thermal energy facilities.

Effective July 2011, the Company changed its operational segments within Liberty Utilities to be aggregated and reported by geography territory. As a result Liberty Utilities reports results under Liberty Utilities (West) Region (currently consisting of Calpeco) and Liberty Utilities (South) Region (currently consisting of Liberty Water). No changes in the aggregation of segmented financial information were required as a result of this change. As additional utilities are acquired, additional reportable segments by geographic territory may be added.

Operational segments

APUC's reportable segments are APCo - Renewable Energy, APCo - Thermal Energy and Liberty Utilities (South) and Liberty Utilities (West). The development activities of APCo are reported under Renewable Energy or Thermal Energy as appropriate. For purposes of evaluating divisional performance, the Company allocates the realized portion of the loss on financial instruments to specific divisions. This allocation is determined when the initial foreign exchange forward contract is entered into. The unrealized portion of any gains or losses on derivatives instruments is not considered in management's evaluation of divisional performance and is therefore allocated and reported in the corporate segment. The interest rate swaps relate to specific debt facilities and gains and losses are allocated in the same manner as interest expense. Amounts relating to the convertible debentures are reported in the corporate segment.

21. Segmented Information (continued)

Operational Segments (continued)

The results of operations and assets for these segments are as follows:

	Year ended December 31, 2011							
	Algonquin Power			Liberty Utilities			Corporate	Total
	Renewable Energy	Thermal Energy	Total	South	West	Total		
Revenue								
Non-regulated energy sales	$ 87,566	$ 46,666	$134,232	$ —	$ —	$ —	$ —	$ 134,232
Regulated energy sales and distribution	—	—	—	—	77,368	77,368	—	77,368
Waste disposal fees	—	16,406	16,406	—	—	—	—	16,406
Regulated water reclamation and distribution	—	—	—	44,989	—	44,989	—	44,989
Other revenue	2,291	1,352	3,643	—	—	—	—	3,643
Total revenue	89,857	64,424	154,281	44,989	77,368	122,357	—	276,638
Operating expenses	29,802	44,485	74,287	22,720	62,511	85,231	38	159,556
	60,055	19,939	79,994	22,269	14,857	37,126	(38)	117,082
Depreciation of property, plant and equipment	(16,903)	(10,684)	(27,587)	(7,993)	(3,813)	(11,806)	—	(39,393)
Amortization of intangible assets	(3,007)	(2,735)	(5,742)	(691)	—	(691)	—	(6,433)
Administration expenses	(10,719)	(700)	(11,419)	(342)	(798)	(1,140)	(4,975)	(17,534)
Write down of long-lived assets	(2,032)	(13,430)	(15,462)	(1,058)	—	(1,058)	—	(16,520)
Gain on foreign exchange	—	—	—	—	—	—	652	652
Interest expense	(8,128)	(1,688)	(9,816)	(5,189)	(4,526)	(9,715)	(10,910)	(30,441)
Interest, dividend and other income	2,143	(6)	2,137	488	—	488	3,034	5,659
Acquisition related costs	—	—	—	(2,301)	(466)	(2,767)	(198)	(2,965)
Loss on derivative financial instruments	(1,068)	—	(1,068)	—	—	—	(4,776)	(5,844)
Earnings / (loss) before income taxes	$ 20,341	$ (9,304)	$ 11,037	$ 5,183	$ 5,254	$ 10,437	$ (17,211)	$ 4,263
Property, plant and equipment	$423,884	155,507	579,391	208,073	158,492	366,565	—	945,956
Intangible assets	25,863	7,088	32,951	—	22,318	22,318	—	55,269
Total assets	482,543	176,269	658,812	252,514	188,399	440,913	182,863	1,282,588
Capital expenditures	25,610	13,601	39,211	10,906	10,261	21,167	367	60,745
Acquisition of operating entities	—	—	—	1,253	98,805	100,058	—	100,058

21. Segmented Information (continued)

Operational Segments (continued)

	Year ended December 31, 2010							
	Algonquin Power			Liberty Utilities			Corporate	Total
	Renewable Energy	Thermal Energy	Total	South	West	Total		
Revenue								
Non regulated energy sales	$ 80,117	$ 49,860	$129,977	$ —	$ —	$ —	$ —	$ 129,977
Waste disposal fees	—	9,039	9,039	—	—	—	—	9,039
Water reclamation and distribution	—	—	—	38,011	—	38,011	—	38,011
Other revenue	2,122	1,209	3,331	—	—	—	—	3,331
Total revenue	82,239	60,108	142,347	38,011	—	38,011	—	180,358
Operating expenses	29,481	43,817	73,298	22,199	—	22,199	—	95,497
	52,758	16,291	69,049	15,812	—	15,812	—	84,861
Depreciation of property, plant and equipment	(17,233)	(11,243)	(28,476)	(7,820)	—	(7,820)	(175)	(36,471)
Amortization of intangible assets	(6,670)	(2,774)	(9,444)	(700)	—	(700)	—	(10,144)
Administration expenses	(4,674)	(1,825)	(6,499)	(1,890)	—	(1,890)	(6,497)	(14,886)
Write down of long-lived assets	(1,836)	(656)	(2,492)	—	—	—	—	(2,492)
Foreign exchange gain	—	—	—	—	—	—	528	528
Interest expense	(7,742)	(770)	(8,512)	(1,911)	—	(1,911)	(14,416)	(24,839)
Interest, dividend and other income	783	633	1,416	149	—	149	3,599	5,164
Acquisition related costs	—	—	—	—	—	—	(3,015)	(3,015)
Loss on derivative financial instruments	(5,486)	—	(5,486)	—	—	—	4,383	(1,103)
Earnings / (loss) before income taxes	9,900	(344)	9,556	3,640	—	3,640	(15,593)	(2,397)
Property, plant and equipment	$412,159	$149,837	$561,996	$199,251	—	$199,251	$ 493	$ 761,740
Intangible assets	28,287	23,104	51,391	22,495	—	22,495	—	73,886
Total assets	467,589	194,906	662,495	237,513	—	237,513	116,941	1,016,949
Capital expenditures	2,331	11,554	13,885	6,644	—	6,644	260	20,789
Acquisition of operating entities	40,281	—	40,281	2,120	1,996	4,116	—	44,397

21. Segmented Information (continued)

Operational Segments (continued)

All energy sales are earned from contracts with large public utilities. The following utilities contributed more than 10% of these total revenues in either 2011 or 2010: Hydro Québec 17% (2010 - 14%), Pacific Gas and Electric 11% (2010 - 10%), Manitoba Hydro 16% (2010 – 15%), and AES 15% (2010 - 18%). The Company has mitigated its credit risk to the extent possible by selling energy to these large utilities in various North American locations.

APUC and its subsidiaries operate in the independent power and utility industries in both Canada and the United States. Information on operations by geographic area is as follows:

	2011	2010
Revenue		
Canada	$ 88,900	$ 72,360
United States	187,738	107,998
	$276,638	$180,358
Property, plant and equipment		
Canada	$474,094	$464,783
United States	471,862	296,957
	$945,956	$761,740
Intangible assets		
Canada	$ 25,863	$ 43,305
United States	29,406	30,581
	$ 55,269	$ 73,886
Other assets		
Canada	$ 3,577	$ 1,415
United States	—	1,940
	$ 3,577	$ 3,355

Revenues are attributed to the two countries based on the location of the underlying generating and utility facilities.

22. Financial instruments

a) Fair Value of financial instruments

	Carrying amount	2011 Fair Value	Carrying amount	2010 Fair value
Cash and cash equivalents	$ 72,887	$ 72,887	$ 4,749	$ 4,749
Short-term investments	833	833	3,674	3,674
Accounts receivable and due from related parties	46,669	46,669	26,593	26,593
Restricted cash	4,693	4,693	3,564	3,564
Notes receivable	24,534	24,534	18,744	18,744
Total financial assets	$149,616	$149,616	$ 57,324	$ 57,324
Accounts payable and due to related parties	10,177	10,177	3,716	3,716
Accrued liabilities	47,102	47,102	29,534	29,534
Dividends payable	9,566	9,566	5,719	5,719
Long-term liabilities	332,716	338,264	259,958	262,117
Convertible debentures	122,297	162,195	181,760	216,769
Interest rate swaps	6,975	6,975	5,440	5,440
Energy forward purchase contracts	1,169	1,169	378	378
Foreign exchange contracts	—	—	45	45
Total financial liabilities	$530,002	$575,448	$486,550	$523,718

The Company has determined that the carrying value of its short-term financial assets and liabilities approximates fair value at December 31, 2011 and 2010 due to the short-term maturity of these instruments.

Long term investments and notes receivable include equity instruments and notes receivable. The equity instruments do not have a quoted market price in an active market, and fair value cannot be reliably measured. Notes receivable fair values have been determined using a discounted cash flow method, using estimated current market rates for similar instruments adjusted for estimated credit risk as determined by management. Such estimate is significantly influenced by unobservable data and therefore this fair value is subject to estimation risk.

APUC has long-term liabilities and convertible debentures at fixed interest rates and variable rates. The estimated fair value is calculated using the current interest rates.

Advances in aid of construction have a carrying value of $75,151 (2010 - $55,115) at December 31, 2011. Portions of these non-interest bearing instruments are payable annually through 2026 and amounts not paid by the contract expiration dates become nonrefundable. Their relative fair values cannot be accurately estimated because future refund payments depend on several variables, including new customer connections, customer consumption levels, and future rate increases. However, the fair value of these amounts would be less than their carrying value due to the non-interest bearing feature.

Fair value estimates are made at a specific point in time, using available information about the financial instrument. These estimates are subjective in nature and often cannot be determined with precision.

22. Financial instruments (continued)

b) Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities accounted for at fair value at December 31, 2011 are as follows:

	Level 1	Level 2	Level 3	Total
Derivative liabilities:				
Energy forward purchase contracts	$ —	$(1,169)	$ —	$(1,169)
Interest rate swap	—	(6,975)	—	(6,975)
	$ —	$(8,144)	$ —	$(8,144)

The Company's accounting policy is to recognize transfers between levels of the fair value hierarchy on the date of the event or change in circumstances that caused the transfer. There was no transfer into or out of level 1, level 2 or level 3 during the years ended December 31, 2011 or 2010.

The fair value of derivative instruments is estimated using forward curves obtained from brokers and market participants, net of estimated credit risk.

The Red Lily conversion option (note 5 (a)) is measured at fair value on a recurring basis using unobservable inputs (Level 3).The fair value is based on an income approach using an option pricing model that includes various inputs such as energy yield function from wind, discount rate and estimated cash flows. There was no change in fair value of $0 during the years ended December 31, 2011 or 2010.

22. Financial instruments (continued)

c) Effect of derivative instruments on the Consolidated Statement of Operations

Loss/(gain) on derivative financial instruments consist of the following:

	2011	2010
Change in unrealized loss/(gain) on derivative financial instruments:		
Foreign exchange contracts	$ (45)	$(1,424)
Interest rate swaps	1,536	(2,787)
Energy forward purchase contracts	833	(2,931)
Total change in unrealized loss/(gain) on derivative financial instruments	$2,324	$(7,142)
Realized loss/(gain) on derivative financial instruments:		
Foreign exchange contracts	$ 691	$ (620)
Interest rate swaps	2,138	5,929
Energy forward purchase contracts	691	2,936
Total realized loss on derivative financial instruments	$3,520	$ 8,245
Loss on derivative financial instruments	$5,844	$ 1,103

(d) Risk Management

In the normal course of business, the Company is exposed to financial risks that potentially impact its operating results. The Company employs risk management strategies with a view to mitigating these risks to the extent possible on a cost effective basis. Derivative financial instruments are used to manage certain exposures to fluctuations in exchange rates, interest rates and commodity prices. The Company does not enter into derivative financial agreements for speculative purposes.

This note provides disclosures relating to the nature and extent of the Company's exposure to risks arising from financial instruments, including credit risk, liquidity risk, foreign currency risk and interest rate risk, and how the Company manages those risks.

Credit Risk

Credit risk is the risk of an unexpected loss if a customer or counterparty to a financial instrument fails to meet its contractual obligations. The Company's financial instruments that are exposed to concentrations of credit risk are primarily cash and cash equivalents, short term investments, accounts receivable and notes receivable. The Company limits its exposure to credit risk with respect to cash equivalents by ensuring available cash is deposited with its senior lenders in Canada all of which have a credit rating of A or better. The Company does not consider the risk associated with accounts receivable to be significant as over 80% of revenue from Power Generation is earned from large utility customers having a credit rating of BBB or better, and revenue is generally invoiced and collected within 45 days.

22. Financial instruments (continued)

The remaining revenue is primarily earned by the Utility Services business unit which consists of water and wastewater utilities in the United States. In this regard, the credit risk related to Utility Services accounts receivable balances of U.S. $4,996 is spread over thousands of customers. The Company has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers. In addition the state regulators of the Company's utilities allow for a reasonable bad debt expense to be incorporated in the rates and therefore ultimately recoverable from rate payers.

As at December 31, 2011 the Company's exposure to credit risk for these financial instruments was as follows:

	December 31, 2011	
	Canadian $	US $
Cash and cash equivalents and restricted cash	$ 69,108	$ 9,149
Short term investments	833	—
Accounts receivable	14,229	29,912
Allowance for Doubtful Accounts	—	(251)
Note Receivable	22,478	2,021
	$106,648	$40,831

There are no material past due amounts in accounts receivable.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company's approach to managing liquidity risk is to ensure, to the extent possible, that it will always have sufficient liquidity to meet liabilities when due. As at December 31, 2011, in addition to cash on hand of $72,887 the Company had $80,400 available to be drawn on its senior debt facility. The senior credit facility contains covenants which may limit amounts available to be drawn. The Company's liabilities mature as follows:

	Due less than 1 year	Due 2 to 3 years	Due 4 to 5 years	Due after 5 years	Total
Long term debt obligations	$ 1,624	$ 3,725	$ 9,556	$317,811	$332,716
Convertible Debentures	59,726	—	—	62,571	122,297
Interest on long term debt	25,571	40,241	37,250	124,807	227,869
Accounts Payable and due to related parties	10,177	—	—	—	10,177
Accrued liabilities	47,102	—	—	—	47,102
Derivative financial instruments:					
Interest Rate Swaps	2,935	4,113	1,096	—	8,144
Capital Lease Payments	231	260	10	—	501
Other obligations	1,063	516	516	7,681	9,776
Total obligations	$148,429	$48,855	$48,428	$512,870	$758,582

22. Financial instruments (continued)

Foreign Currency Risk

The Company periodically uses a combination of foreign exchange forward contracts and spot purchases to manage its foreign exchange exposure on cash flows generated from the U.S. operations. APUC only enters into foreign exchange forward contracts with major Canadian financial institutions having a credit rating of A or better, thus reducing credit risk on these forward contracts.

At December 31, 2011, the Company had no outstanding forward foreign exchange contracts. As at December 31, 2010, APUC had outstanding foreign exchange forward contracts to sell US$3,000 at an average rate of $1.00 and having a fair value liability of $45.

Interest Rate Risk

The Company is exposed to interest rate fluctuations related to certain of its floating rate debt obligations, including certain project specific debt and its revolving credit facility, its interest rate swaps as well as interest earned on its cash on hand. The Company does not currently hedge that risk.

In connection with the project debt at the St. Leon facility which was repaid during 2011, APCo previously entered into an interest rate swap to hedge the floating interest rate on the project debt. Under the terms of the swap, the Company pays a fixed interest rate of 4.47% on a notional amount of $67.8 million and receives floating interest at 90 day CDOR, up to the expiry of the swap in September 2015. At December 31, 2011, the estimated fair value of the interest rate swap was a liability of $6,975 (2010 –liability of $5,440). This interest rate swap is not being accounted for as a hedge and consequently, changes in fair value are recorded in earnings as they occur.

Market Risk

APUC provides energy requirements to various customers under contract at fixed rates. While the Tinker Assets are expected to provide a portion of the energy required to service these customers, APUC anticipates having to purchase a portion of its energy requirements at the ISO NE spot rates to supplement self-generated energy.

This risk is mitigated though the use of short term financial forward energy purchase contracts which are derivative instruments. In January 2011, APUC entered into electricity derivative contracts with Nextera (“counterparty”) for a term ending February 2014, which are net settled fixed-for-floating swaps whereby APUC will pay a fixed price and receive the floating or indexed price on a notional quantity of 162,128 MW-hrs of energy over the remainder of the contact term at an average rate of approximately $51.40 per MW-hr. The estimated fair value of these forward energy hedge contracts at December 31, 2011 was a net liability of $1,169 (December 31, 2010 - $nil).

23. Capital disclosures

The Company views its capital structure in terms of its debt levels, both at a project and an overall company level, in conjunction with its equity balances.

The Company's objectives when managing capital are:

- To maintain appropriate debt and equity levels in conjunction with standard industry practices and to limit financial constraints on the use of capital.
- To ensure capital is available to finance capital expenditures sufficient to maintain existing assets.
- To ensure generation of cash is sufficient to fund sustainable distributions to Unitholders as well as meet current tax and internal capital requirements.
- To maintain sufficient cash reserves on hand to ensure sustainable dividends made to shareholders.
- To have proper credit facilities available for ongoing investment in growth and investment in development opportunities.

The Company monitors its cash position on a regular basis to ensure funds are available to meet current operating as well as capital expenditures. In addition, the Company regularly reviews its capital structure to ensure its individual business units are using a capital structure which is appropriate for their respective industries.

24. Comparative figures

Certain of the comparative figures have been reclassified to conform with the financial statement presentation adopted in the current year.

Management's Discussion and Analysis

(All figures are in thousands of Canadian dollars, except per share and convertible debenture amounts or where otherwise noted)

Management of Algonquin Power & Utilities Corp. ("APUC") has prepared the following discussion and analysis to provide information to assist its shareholders' understanding of the financial results for the three and twelve months ended December 31, 2011. This Management's Discussion and Analysis ("MD&A") should be read in conjunction with APUC's audited consolidated financial statements for the years ended December 31, 2011 and 2010 prepared in accordance with U.S. generally accepted accounting principles ("GAAP"). See *Change in Accounting Policies* for a discussion on the reasons for this change. This material is available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com. Additional information about APUC, including the most recent Annual Information Form ("AIF") can be found on SEDAR at www.sedar.com.

This MD&A is based on information available to management as of March 18, 2012.

Caution concerning forward-looking statements and non-GAAP Measures

Certain statements included herein contain forward-looking information within the meaning of certain securities laws. These statements reflect the views of APUC with respect to future events, based upon assumptions relating to, among others, the performance of APUC's assets and the business, interest and exchange rates, commodity market prices, and the financial and regulatory climate in which it operates. These forward looking statements include, among others, statements with respect to the expected performance of APUC, its future plans and its dividends to shareholders. Statements containing expressions such as "anticipates", "believes", "continues", "could", "expect", "estimates", "intends", "may", "outlook", "plans", "project", "strives", "will", and similar expressions generally constitute forward-looking statements.

Since forward-looking statements relate to future events and conditions, by their very nature they require APUC to make assumptions and involve inherent risks and uncertainties. APUC cautions that although it believes its assumptions are reasonable in the circumstances, these risks and uncertainties give rise to the possibility that actual results may differ materially from the expectations set out in the forward-looking statements. Material risk factors include the impact of movements in exchange rates and interest rates; the effects of changes in environmental and other laws and regulatory policy applicable to the energy and utilities sectors; decisions taken by regulators on monetary policy; and the state of the Canadian and the United States ("U.S.") economies and accompanying business climate. APUC cautions that this list is not exhaustive, and other factors could adversely affect results. Given these risks, undue reliance should not be placed on these forward-looking statements, which apply only as of their dates. APUC reviews material forward-looking information it has presented, at a minimum, on a quarterly basis. APUC is not obligated to nor does it intend to update or revise any forward-looking statements, whether as a result of new information, future developments or otherwise, except as required by law.

The terms "adjusted net earnings", "adjusted earnings before interest, taxes, depreciation and amortization" ("Adjusted EBITDA") and "per share cash provided by operating activities" are used throughout this MD&A. The terms "adjusted net earnings", "per share cash provided by operating activities" and Adjusted EBITDA are not recognized measures under GAAP. There is no standardized measure of "adjusted net earnings", Adjusted EBITDA and "per share cash provided by operating activities" consequently APUC's method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A calculation and analysis of "adjusted net earnings", Adjusted EBITDA and "per share cash provided by operating activities" can be found throughout this MD&A.

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

Overview and Business Strategy

APUC is incorporated under the Canada Business Corporations Act. 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 $0.07 per share or $0.28 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 cash available for distribution and earnings together with an assessment of the growth prospects available to APUC. APUC strives to achieve its results in the context of a moderate risk profile consistent with top-quartile North American power and utility operations.

APUC currently conducts its business primarily through two autonomous subsidiaries: Algonquin Power Co. ("APCo") which owns and operates a diversified portfolio of renewable energy assets and Liberty Utilities Co. ("Liberty Utilities") which owns and operates a portfolio of North American rate regulated utilities.

Algonquin Power Co.

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. As at December 31, 2011, APCo owns or has interests in hydroelectric facilities operating in Ontario, Québec, Newfoundland, Alberta, New Brunswick, New York State, New Hampshire, Vermont, Maine and New Jersey with a combined generating capacity of approximately 165 MW. APCo also owns a 104 MW wind powered generating station in Manitoba and holds exchangeable debt securities in a 26 MW wind powered generating station completed in early 2011 in Saskatchewan. All of the electrical output from the wind energy facilities are sold pursuant to long term power purchase agreements ("PPAs") with major utilities which have a weighted average remaining contract life of 20 years. Approximately 80% of the electrical output from the hydroelectric facilities is sold pursuant to long term PPAs with major utilities which have a weighted average remaining contract life of 8.5 years.

APCo owns thermal energy facilities with approximately 120 MW of installed generating capacity and holds ownership interests in three facilities having gross installed capacity of approximately 200 MW. Approximately 67% of the electrical output from the owned thermal facilities is sold pursuant to long term PPAs with major utilities and which have a weighted average remaining contract life of 11 years.

Liberty Utilities Co.

Liberty Utilities provides rate regulated electricity, natural gas and, water distribution and wastewater collection utility services. Liberty Utilities' underlying business strategy is to be a leading provider of safe, high quality and reliable utility services through a nationwide portfolio of moderate sized utilities and deliver stable and predictable earnings to APUC from these utility operations. In addition to encouraging and supporting organic growth within its service territories, Liberty Utilities is focused on delivering continued growth in earnings through acquisition opportunities which accretively expand its utility business portfolio. The utility businesses owned by Liberty Utilities operate under rate regulation, generally overseen by the public utility commissions of the states in which they operate. As a result of the current and expected growth of Liberty Utilities, Liberty Utilities has elected to organize the management of its utility operations by geographic region rather than by line of business. As a result of this decision, Liberty Utilities businesses operate under two separately managed regions - Liberty Utilities (South) and Liberty Utilities (West).

Liberty Utilities (South) operates in the states of Arizona, Texas, Missouri and Illinois and currently provides regulated water and wastewater utility services to approximately 76,000 customers in those states.

Liberty Utilities (West) operates in the state of California and currently provides regulated local electrical distribution utility services to approximately 47,000 customers located in the Lake Tahoe region of California; on January 1, 2011, in partnership with Emera Inc. ("Emera"), Liberty Utilities (West) acquired the California-based electricity distribution utility and related generation assets (the "California Utility") from NV Energy.

As the currently committed growth initiatives are completed, additional management regions will be created. Liberty Utilities (East) will be formed to initially deliver electrical and natural gas distribution services to 126,000 customers to be acquired through the acquisition of Granite State Electric Company ("Granite State") and EnergyNorth Natural Gas, Inc., ("EnergyNorth"). Liberty Utilities (Central) will be created initially to manage the delivery of Liberty Utilities gas distribution services in Missouri, Illinois and Iowa following the acquisition of certain gas distribution assets from ATMOS Energy Corporation ("Atmos").

Major Highlights

Corporate Highlights

Dividend Increased to $0.28 for each Common Share

On March 3, 2011, the Board approved an increase in the dividend from $0.24 to $0.26 on an annualized basis. On August 11, 2011, the Board approved a further dividend increase of $0.02 bringing the total dividend to $0.28, paid quarterly at the rate of $0.07 per common share. In approving the increase in dividends, the Board considered the continuing contributions of growth initiatives that began in 2010 and the significant progress made with regards to implementing additional growth initiatives announced in 2011 that have raised the growth profile for APUC's earnings and cash flows. These new growth initiatives, discussed in more detail below, include the acquisition of additional natural gas and electric utilities as well as new wind power generating projects to be built over the next several years.

APUC believes that the increase in dividend is consistent with its stated strategy of delivering total shareholder return comprised of attractive current dividend yield and capital appreciation founded on increased earnings and cash flows.

Strengthened Liquidity – 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 16,869,000 common shares under the Offering for the total gross proceeds of approximately $95.3 million.

The net proceeds of the Offering will be used to fund a portion of the investment related to previously announced growth initiatives for both Liberty Utilities and APCo, to partially repay existing indebtedness and for other general corporate purposes.

Strengthened Balance Sheet – Conversion of Convertible Debentures to Equity

Effective May 16, 2011 ("Redemption Date"), APUC redeemed $2.1 million, all of the remaining issued and outstanding, Series 1A 7.5% convertible unsecured subordinated debentures due November 30, 2014 ("Series 1A Debentures") and issued 430,666 share of APUC. Between January 1, 2011 and the Redemption Date, a principal amount of $60,339 of Series 1A Debentures were converted into 14,788,976 shares of APUC.

Effective February 24, 2012 ("Series 2A Redemption Date"), APUC redeemed $57.0 million, representing the remaining issued and outstanding, Series 2A Debentures by issuing and delivering 9,836,520 APUC shares. Between January 1, 2012 and the Series 2A Redemption Date, a principal amount of $2.9 million of Series 2A Debentures were converted into 485,998 shares of APUC.

Strategic Investment Agreement with Emera

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

The Strategic 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 projects within its service territories and large electric utilities. These “areas of pursuit” are intended to represent investment areas in which there is potential overlap between Algonquin and Emera and are not exhaustive of either company’s business focus and do not limit in any way the activities which either APUC or Emera can undertake. Each of APUC or Emera are free to undertake independently investments within their own “area of pursuit” and outside the other party’s “areas of pursuit”. Under the Strategic Agreement, to the extent either APUC or Emera encounter opportunities which fall within the other’s “areas of pursuit”, they are committed to work with the other party in the development of such investment opportunities.

As an element of the Strategic Agreement, Emera’s allowed common equity interest in APUC will be increased from 15% to 25%. The Strategic Agreement was approved by shareholders at the annual and special general meeting held on June 21, 2011.

Liberty Utilities Highlights

California Utility Acquisition and Senior Debt Financing

On January 1, 2011, APUC, in partnership with Emera, acquired the assets comprising the California Utility for a gross purchase price of U.S. $136.1 million, subject to certain working capital and other closing adjustments. Liberty Utilities owns 50.001% and Emera owns 49.999% of California Pacific Utility Ventures LLC, which owns 100% of the purchaser of the California Utility assets, California Pacific Electric Company (“Calpeco”).

Filing of Approval Application for 100% of California Utility

On April 29, 2011, Emera agreed to sell its 49.999% direct ownership in the California Utility to Liberty Utilities, with closing of such transaction subject to regulatory approval. As consideration, Emera will receive 8.211 million APUC shares in two tranches; approximately half of the shares will be issued following regulatory approval of the transfer of 100% of the California Utility to Liberty Utilities (expected in early 2012) and the balance of the shares will be issued following completion of the California Utility’s first rate case, expected to be completed in early 2013.

New Hampshire Utility Acquisitions

On December 9th, 2010 Liberty Utilities entered into agreements to acquire all issued and outstanding shares of Granite State Electric Company (“Granite State”), a regulated electric distribution utility in New Hampshire, and EnergyNorth Natural Gas, Inc. (“EnergyNorth”), a regulated natural gas distribution utility in New Hampshire, both from National Grid USA (“National Grid”), for total consideration of U.S. $285.0 million plus certain working capital adjustments. Liberty Utilities expects to acquire assets for rate making purposes of approximately U.S. $250 million.

The closing of the transaction is subject to approval by the New Hampshire Public Utilities Commission (“NHPUC”). Liberty Utilities is currently proceeding through the regulatory approval process. A series of technical sessions with the NHPUC have been held to review the merits of the transaction, identify key transitional issues and resolve issues raised by commission staff, the consumer advocate and other interveners. Liberty Utilities and National Grid are now working with the NHPUC Staff and Consumer Advocate to prepare a settlement recommendation to present to the Commissioners of the NHPUC for consideration and ultimate approval. The current regulatory hearing schedule should allow for a public hearing in late Q1 2012, with a commission decision expected shortly thereafter. This would likely to result in closing occurring towards the end of Q2 2012.

Midwest Utility Acquisitions

On May 13, 2011, Liberty Utilities entered into an agreement with Atmos to acquire their regulated natural gas distribution utility assets (the “Midwest Gas Utilities”) located in Missouri, Iowa, and Illinois. Total purchase price for the Midwest Gas Utilities is approximately U.S. $124 million, subject to certain working capital and other closing adjustments. Liberty Utilities expects to acquire assets for rate making purposes of approximately U.S. $112 million.

The closing of the transaction is subject to approval by the Missouri Public Service Commission ("MPSC"), Iowa Utilities Board ("IUB"), and Illinois Commerce Commission ("ICC"). Liberty Utilities has received approval from the IUB and has entered a unanimous stipulation with the MPSC. Liberty Utilities is currently proceeding through the regulatory approval process with the ICC which requires the company, Atmos and the ICC staff to review the merits of the transaction. A hearing on a limited set of issues was held in Illinois in January 2012, and a proposed ICC decision is expected in Q2 2012. Management expects closing to occur towards the end of Q2 2012.

Liberty Utilities Credit Facility

On January 19, 2012, Liberty Utilities entered into an agreement for a U.S. $80 million senior unsecured revolving credit facility (the "Liberty Facility") with a three year term. Initially, U.S. $25 million will be available immediately to support the operations of Liberty Utilities and its current subsidiaries. The additional U.S. $55 million will be automatically available to Liberty Utilities to support operations and working capital requirements of all committed regulated utility acquisitions following the closing of the previously announced acquisition of Granite State and EnergyNorth. The Liberty Facility can be increased to accommodate future working capital needs or other requirements.

Algonquin Power Co. Highlights

Acquisition of U.S. Wind Farms

On March 9, 2012, APCo entered into an agreement to acquire a 51% majority interest in a 480 MW portfolio of four wind power projects in the United States (the "Projects") from Gamesa Corporación Tecnológica, S.A. ("Gamesa"). APCo will contribute U.S. $269 million to partially fund the acquisition of the Projects; tax assisted equity investors will contribute U.S. $360 million. APCo intends to finance its investment with approximately 45% debt and 55% equity. The portfolio will be acquired in two stages; closing of two existing wind farms is expected to occur promptly following receipt of regulatory approval and the acquisition of the remaining two wind farms following their respective commissioning near the end of 2012.

The Projects consist of four facilities, Minonk (200MW), Senate (150MW), Pocahontas Prairie (80MW) and Sandy Ridge (50MW) located in the states of Illinois, Texas, Iowa and Pennsylvania, respectively. Pocahontas Prairie and Sandy Ridge have recently reached their commercial operation dates ("COD") in February 2012, and Senate and Minonk are in construction with COD anticipated in Q4 2012. Total annual energy production from the four facilities is expected to be 1,644 GW-hrs per year. The Projects are comprised of 240 Gamesa G9X-2.0 MW wind turbines. The Projects each have entered into a 20 year contract with Gamesa to provide operations, warranty and maintenance services for the wind turbines and balance of plant facilities.

The Projects have long term, fixed price power sales contracts (the "Power Sales Contracts") with a weighted average life of 11.8 years (Minonk and Sandy Ridge 10 years, Senate 15 years). Approximately 73% of energy revenues would be earned under the Power Sales Contracts. All energy produced in excess of that sold under the Power Sales Contracts, together with ancillary services including capacity and renewable energy credits, will be sold into the energy markets in which the facilities are located.

St. Leon Facility Expansion

On July 18, 2011, APCo entered into a 25-year power purchase agreement with Manitoba Hydro in respect of a 16.5 MW expansion ("St. Leon II") of its existing St. Leon wind energy project located in the Province of Manitoba.

Construction of this project commenced on August 30, 2011. The final turbine was erected in February 2012 and the project is generating energy on all units as of March 1, 2012. The total capital cost of the

project is expected to be $29.5 million. The project is expected to achieve commercial operation early in the second quarter of 2012 with revenues in the first full year of operating following commissioning expected to be $3.8 million.

Red Lily Wind Project

On February 28, 2011 the 26.4 MW wind generation facility in southeastern Saskatchewan ("Red Lily I") commenced commercial operation under the PPA. APUC's investment in Red Lily I has been initially structured in the form of senior and subordinated debt investment of approximately $19.6 million with returns to APUC from the project coming in the form of interest payments and other fees in 2011. APUC earned $1.6 million in interest income and $1.9 million in other payments and fees in 2011. APUC has the option to formally exchange its debt investment for a 75% equity position in the facility in 2016.

New Projects Under Development

As of March 18, 2012, APCo had been awarded or acquired interests in seven major power development projects that significantly expands the company's electrical generation capacity by 350 MW and once completed will increase the company's annual generation production by over 1,200 GWhrs. Each project has a power purchase agreement with a Canadian provincial utility and has a contract length of 20 years or longer.

The following summarizes a number of projects under development and for which PPA's have been awarded since December 2010.

Project Name (Location)	Location	Size (MW)	Estimated Capital Cost	Commercial Operation	PPA Term	Production GWhr
Chaplin Wind	Saskatchewan	177	$ 355.0	2016	25	720.0
Amherst Island	Ontario	75	$ 230.0	2014	25	247.0
Morse Wind [1]	Saskatchewan	25	$ 70.0	2014	20	93.0
St. Damase	Quebec	24	$ 70.0	2013	20	86.0
Val Eo	Quebec	24	$ 70.0	2015	20	66.0
St. Leon II	Manitoba	17	$ 30.0	2012	25	58.0
Cornwall Solar	Ontario	10	$ 45.0	2013	20	13.4
Total		**352**	**$ 870.0**			**1,283.4**

[1] The Morse Wind Project is comprised of three contiguous projects with 25 MW in aggregate installed generating capacity. The two 10 MW PPA's were awarded in May 2010 and the 5 MW PPA was awarded in June 2011.

A more detailed discussion of these projects is presented within the *APCo: Development Division* business unit analysis.

Senior Unsecured Debentures

On July 25, 2011, APCo issued $135 million in senior unsecured debentures (the "Senior Unsecured Debentures"). The net proceeds from the Senior Unsecured 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 "Facility"). The Senior Unsecured 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.

Credit Facility Renewal

On February 14, 2011 APCo renewed the Facility with its bank syndicate for a three year term with a maturity date of February 14, 2014. The committed credit under the Facility is $120 million.

2011 Annual results from operations

APUC continued to show strong results through 2011. Over the past two years, APUC has focused its efforts on a number of value creation initiatives that, through their completion, are now contributing to the growth evident in APUC revenues, adjusted EBITDA and net earnings. These initiatives include Liberty Utilities' acquisition of the California Utility and successful prosecution of rate cases, APCo's refurbishment of the Energy from Waste facility, acquisition of the Tinker Hydro facility and completion of construction and commissioning of the Red Lily I Wind Farm. As a result, for the year ended December 31, 2011, APUC reported total revenue of $276.6 million as compared to $180.4 million during the same period in 2010, an increase of $96.2 million or 53%.

Adjusted EBITDA in the year ended December 31, 2011 totalled $105.2 million as compared to $75.1 million during the same period in 2010, an increase of $30.1 million or 40%. (see Non-GAAP Performance Measures). For the year ended December 31, 2011, net earnings attributable to Shareholders totalled $23.4 million as compared to $18.0 million during the same period in 2010, an increase of $5.4 million.

Key Selected Annual Financial Information

	Year ended December 31		
	2011 (millions)	**2010 (millions)**	**2009[5] (millions)**
Revenue	**$ 276.6**	$ 180.4	$ 187.3
Adjusted EBITDA [1, 3]	**$ 105.2**	$ 75.1	$ 79.4
Cash provided by Operating Activities	**69.7**	41.4	48.0
Net earnings attributable to Shareholders	**23.4**	18.0	31.3
Adjusted net earnings [1, 3]	**41.6**	22.5	30.5
Dividend declared to Shareholders	**32.4**	22.8	19.3
Per share			
Basic net earnings	**$ 0.20**	$ 0.19	$ 0.39
Adjusted net earnings [1, 3]	**$ 0.36**	$ 0.24	$ 0.38
Diluted net earnings	**$ 0.20**	$ 0.19	$ 0.39
Cash provided by Operating Activities [2, 3]	**$ 0.60**	$ 0.44	$ 0.60
Dividends declared to Shareholders	**$ 0.27**	$ 0.24	$ 0.24
Total Assets	**1,282.6**	1,016.9	1,013.4
Long Term Liabilities[4]	**332.7**	260.0	241.4

1 APUC uses Adjusted EBITDA and Adjusted net earnings to enhance assessment and understanding of the operating performance of APUC without the effects of certain accounting adjustments which are derived from a number of non-operating factors, accounting methods and assumptions.

2 APUC uses per share cash provided by operating activities to enhance assessment and understanding of the performance of APUC.

3 Non-GAAP measure - see applicable section later in this MD&A and the caution regarding non-GAAP measures on page 1.

4 Includes Long-term liabilities and Current portion of long-term liabilities.

5 Presented using Canadian Generally Accepted Accounting Principles.

The major factors resulting in the increase in APUC revenue in the year ended December 31, 2011 as compared to the corresponding period in 2010, are set out as follows:

	Year ended December 31, 2011 (millions)
Comparative Prior Period Revenue	$ 180.4
Significant Changes:	
Acquisition of the California Utility – January 1, 2011	78.1
Liberty Utilities (South) revenue increases primarily due to rate case approvals	8.8
Energy-from-Waste facility	7.6
Effect of hydrology resource compared to comparable period in prior year	6.8
Effect of wind resource compared to comparable period in prior year	3.0
Impact of the weaker U.S. dollar	(5.4)
Tinker Hydro/ Algonquin Energy Services (“AES”)	(1.4)
Windsor Locks	(0.9)
All Other	(0.4)
Current Period Revenue	$ 276.6

A more detailed discussion of these factors is presented within the business unit analysis.

APUC reports its results in Canadian dollars. For the year ended December 31, 2011, APUC experienced an average U.S. exchange rate to each Canadian dollar of approximately U.S. $0.989 as compared to U.S. $1.031 in the same period in 2010. As such, any year over year variance in revenue or expenses, in local currency, at any of APUC’s U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC’s reporting currency.

Adjusted EBITDA in the year ended December 31, 2011 totalled $105.2 million as compared to $75.1 million during the same period in 2010, an increase of $30.1 million or 40%. The increase in Adjusted EBITDA is primarily due to increased earnings from operations primarily resulting from Liberty Utilities’ acquisition of the California Utility and increased revenues resulting from the completion of rate cases, improved average hydrology and wind resources in APCo’s Renewable Energy division and improved results from the EFW facility. This increase was partially offset by lower results at Windsor Locks and Tinker facilities, as well as the impact of the weaker U.S. dollar as compared to the same period in 2010. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see Non-GAAP Performance Measures).

For the year ended December 31, 2011, net earnings attributable to Shareholders totalled $23.4 million as compared to $18.0 million during the same period in 2010, an increase of $5.4 million. Basic net earnings per share totalled $0.20 for the year ended December 31, 2011, as compared to $0.19 during the same period in 2010.

For the year ended December 31, 2011, net earnings totalled $27.3 million as compared to $18.4 million during the same period in 2010, an increase of $8.9 million. A number of factors resulted in increased net earnings, including an increase of $32.2 million due to increased earnings from operating facilities, $0.5 million in increased interest and dividend income, $2.2 million related to increased recoveries of income tax expense (see - *2011 Annual Corporate and Other Expenses*) and $0.8 million due to decreased amortization and depreciation expense. These items were partially offset by increased management and administration expenses of $2.6 million, $5.6 million due to increased interest expense, $14.0 million due write downs of intangibles and property, plant and equipment (see - *2011 Annual Corporate and Other Expenses*) and $4.7 million due to increased losses on derivative financial instruments as compared to the same period in 2010.

During the year ended December 31, 2011, cash provided by operating activities totalled $69.7 million or $0.60 per share as compared to cash provided by operating activities of $41.4 million, or $0.44 per share during the same period in 2010, an increase of approximately 36% per share. Cash per share provided by operating activities is a non-GAAP measure. Cash provided by operating activities exceeded dividends declared by 2.1 times during the year ended December 31, 2011 as compared to 1.8 times dividends paid during the same period in 2010. The change in cash provided by operating activities after changes in working capital in the year ended December 31, 2011, is primarily due to increased cash from operations, partially offset by increased interest expense and increased management and administration expense as compared to the same period in 2010.

2011 Fourth quarter results from operations

Key Selected Fourth Quarter Financial Information

	Three months ended December 31	
	2011 (millions)	**2010 (millions)**
Revenue	**$ 72.1**	$ 48.4
Adjusted EBITDA [1, 3]	**$ 24.3**	$ 20.8
Cash provided by Operating Activities	**4.6**	15.1
Net earnings (loss) attributable to Shareholders	**(8.5)**	15.6
Adjusted net earnings [1, 3]	**6.7**	18.2
Dividends declared to Shareholders	**9.5**	5.7
Per share		
Basic net earnings (loss)	**$ (0.07)**	$ 0.17
Adjusted net earnings [1, 3]	**$ 0.05**	$ 0.19
Diluted net earnings (loss)	**$ (0.07)**	$ 0.17
Cash provided by Operating Activities [2, 3]	**$ 0.03**	$ 0.17
Dividends declared to Shareholders	**$ 0.07**	$ 0.06

[1] APUC uses Adjusted EBITDA and Adjusted net earnings to enhance assessment and understanding of the operating performance of APUC without the effects of certain accounting adjustments which are derived from a number of non-operating factors, accounting methods and assumptions.

[2] APUC uses per share cash from operating activities to enhance assessment and understanding of the performance of APUC.

[3] Non-GAAP measure - see applicable section later in this MD&A and the caution regarding non-GAAP measures on page 1.

For the three months ended December 31, 2011, APUC reported total revenue of $72.1 million as compared to $48.4 million during the same period in 2010, an increase of $23.7 million or 49%. The major factors resulting in the increase in APUC revenue in the three months ended December 31, 2011 as compared to the corresponding period in 2010 are set out as follows:

	Three months ended December 31, 2011 (millions)
Comparative Prior Period Revenue	$ 48.4
Significant Changes:	
Acquisition of the California Utility – January 1, 2011	20.8
Liberty Utilities (South) revenue increases primarily due to rate case approvals	1.4
Effect of wind resource compared to comparable period in prior year	1.6
Windsor Locks	(0.9)
Impact of the stronger U.S. dollar	0.7
Other	0.1
Current Period Revenue	$ 72.1

A more detailed discussion of these factors is presented within the business unit analysis.

APUC reports its results in Canadian dollars. For the three months ended December 31, 2011, APUC experienced an average U.S. exchange rate for each Canadian dollar of approximately U.S. $1.023 as compared to U.S. $1.013 in the same period in 2010. As such, any quarter over quarter variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's reporting currency.

Adjusted EBITDA in the three months ended December 31, 2011 totalled $24.3 million as compared to $20.8 million during the same period in 2010, an increase of $3.5 million or 17%. The increase in Adjusted EBITDA is primarily due to increased earnings from operations primarily resulting from Liberty Utilities' acquisition of the California Utility and increased revenues resulting from the completion of rate cases, improved wind resource in APCo's Renewable Energy and the impact of the stronger U.S. dollar. This increase was partially offset by lower results at Windsor Locks as compared to the same period in 2010. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see Non-GAAP Performance Measures).

For the three months ended December 31, 2011, net loss attributable to Shareholders totalled $8.5 million as compared to net earnings of $15.6 million during the same period in 2010, a decrease of $24.2 million. Net loss per share totalled ($0.07) for the three months ended December 31, 2011, as compared to net earnings of $0.17 during the same period in 2010.

For the three months ended December 31, 2011, net loss totalled $8.1 million as compared to net earnings of $15.8 million during the same period in 2010, a decrease of $23.9 million. A number of factors resulted in decreased net earnings for the three months ended December 31, 2011, including $0.5 million related to increased loss on foreign exchange, $1.1 million due to increased interest expense, $9.8 million related to lower recoveries of income tax expense (see *Fourth Quarter Corporate and Other Expenses)*, $14.0 million due to write downs of intangibles and property, plant and equipment (see - *Fourth Quarter Corporate and Other Expenses*) and $3.4 million due to increased losses on derivative financial instruments as compared to the same period in 2010. These items were partially offset by an increase of $2.9 million due to increased earnings from operating facilities, a decrease of $0.3 million due to reduced depreciation and amortization expense, a decrease of $0.3 million due to reduced management and administration expense and a decrease of $1.2 million due to reduced acquisition costs as compared to the same period in 2010.

During the three months ended December 31, 2011, cash provided by operating activities totalled $4.6 million or $0.04 per share as compared to cash provided by operating activities of $15.1 million, or $0.16 per share during the same period in 2010. Cash per share provided by operating activities is a non-GAAP measure. The change in cash provided by operating activities after changes in working capital in the three months ended December 31, 2011, is primarily due to a modest increase in cash from operations, offset by increased interest expense and reduced tax recoveries as compared to the same period in 2010.

Outlook

APCo

The APCo Renewable Energy division is expected to perform based on long-term average resource conditions for hydrology and long-term average wind resources in the first quarter of 2012.

APCo's energy services business, AES, anticipates that, based on the expected load forecast for its existing contracts, the APCo owned assets will provide almost 50% of the energy required to service its customers in the first quarter of 2012.

APCo's Thermal Energy division's Sanger facility will be offline during the majority of the first quarter of 2012 to accommodate certain transmission system upgrades being undertaken by PG&E and to allow for planned major maintenance. During this period capacity payments from PG&E will continue, however energy sales will be curtailed during this period. As a result, revenues from the Sanger facility are expected to be approximately $1.3 million lower than revenues achieved in the first quarter of 2011.

The Windsor Locks natural gas fired cogeneration facility will continue to sell a portion of its electricity capacity and all of its steam capacity to the industrial host with the balance of the electrical capacity available to be sold either into the Independent System Operator New England ("ISO NE") day-ahead market or to industrial customers through AES. It is anticipated that performance during the first quarter of 2012 will be in line with expectations.

The EFW facility "tip or pay" waste supply agreement with the Region of Peel (the "Region") expires in April 2012. On February 23, 2012, the Peel Regional Council decided to seek competitive proposals from several waste management companies, including APCo. APCo is participating in this proposal process. In addition, the facility is currently permitted to accept commercial and industrial waste from certain other jurisdictions outside of the Region of Peel. APCo is actively sourcing alternative supply options with respect to municipal solid waste from other jurisdictions to ensure a continued supply of waste for the facility. For additional information, see *APCo Divisional Outlook - Thermal Energy*.

On January 27, 2012, APCo announced that it plans not to proceed with the previously announced U.S. $83 million minority investment in First Wind Holdings, LLC's ("First Wind") wind energy facilities portfolio in the North East United States. The longer than anticipated regulatory process in Maine and the number of new acquisition and development opportunities announced since April 2011 contributed to the decision not to proceed with the investment.

Liberty Utilities

Liberty Utilities (South) expects continuing modest customer growth throughout its service territories in 2012.

Revenue increases from rate cases at the Rio Rico facility and the Bella Vista facility completed in the first quarter of 2011 are anticipated to contribute moderate additional revenue in Liberty Utilities (South) in the first quarter of 2012 as compared to the same period in 2011.

Liberty Utilities (West) expects modest customer growth within its service territories in 2012. Liberty Utilities (West) anticipates that the California Utility should meet expectations for the first quarter of 2012.

On February 17, 2012, the California Utility filed a general rate case with the California Public Utilities Commission ("CPUC") seeking, among other things, an increase of 10.0%, or $7.5 million in general rates. The California Utility's proposed procedural schedule contemplates rates to be implemented on January 1, 2013.



APCo: Renewable Energy

	Three months ended December 31			Year ended December 31		
	Long Term Average Resource	2011	2010	Long Term Average Resource	2011	2010
Performance (GW-hrs sold)						
Quebec Region	**73.6**	**79.3**	84.1	**279.3**	**304.4**	275.9
Ontario Region	**32.1**	**28.2**	20.2	**134.6**	**121.1**	90.2
Manitoba Region	**105.0**	**119.7**	97.2	**372.0**	**383.8**	343.1
Saskatchewan Region*	**23.3**	**27.7**	—	**66.7**	**68.0**	—
New England Region	**13.4**	**23.7**	13.4	**58.8**	**70.2**	47.9
New York Region	**23.8**	**22.4**	24.4	**90.4**	**92.6**	79.6
Western Region	**12.7**	**11.8**	10.5	**65.9**	**65.5**	59.1
Maritime Region	**35.0**	**40.2**	55.5	**136.9**	**183.0**	148.6
Total	**318.9**	**353.0**	305.3	**1,204.6**	**1,288.6**	1,044.4
Revenue**						
Energy sales		**$23,816**	$21,867		**$ 87,566**	$ 80,117
Less:						
Cost of Sales – Energy***		**(737)**	(431)		**(3,762)**	(5,047)
Net Energy Sales		**$23,079**	$21,436		**$ 83,804**	$ 75,070
Other Revenue		**317**	563		**2,291**	2,122
Total Net Revenue		**$23,396**	$21,999		**$ 86,095**	$ 77,192
Expenses						
Operating expenses		**(7,933)**	(7,013)		**(26,116)**	(24,434)
Interest and Other income		**613**	151		**2,143**	783
Division operating profit (including other income)		**$16,076**	$15,137		**$ 62,122**	$ 53,541

* Actual production in the Saskatchewan Region reflects production since Red Lily I achieved commercial operation on February 23, 2011. APUC does not consolidate the operating results from this facility in its financial statements. Production from the facility is included as APUC manages the facility and has an option to acquire a 75% equity interest in the facility in 2016. The long term average resource reflects three and twelve months of production.

** While most of APCo's PPAs include annual rate increases, a change to the weighted average production levels resulting in higher average production from facilities that earn lower energy rates can result in a lower weighted average energy rate earned by the division, as compared to the same period in the prior year.

*** Cost of Sales - Energy consists of energy purchases by AES which is resold to its retail and industrial customers. Under GAAP, in APUC's consolidated Financial Statements, these amounts are included in operating expenses.

2011 Annual Operating Results

For the year ended December 31, 2011, the Renewable Energy division produced 1,288.6 GWhrs of electricity, as compared to 1,044.4 GWhrs produced in the comparable period, an increase of 23%. The increased generation is primarily due to strong average hydrology in the year as compared to the comparable period in 2010. This level of production in 2011 represents sufficient renewable energy to supply the equivalent of 72,000 homes on an annualized basis with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 710,000 tons of CO_2 gas was prevented from entering the atmosphere in the year ended December 31, 2011.

During the year ended December 31, 2011, the division generated electricity equal to 107% of long-term projected average resources (wind and hydrology) as compared to 90% during the same period in 2010. In the year ended December 31, 2011, the Quebec, New England and Maritimes regions experienced resources significantly higher than long-term averages, producing 9%, 19%, and 34%, respectively, above long-term average resources, while the Manitoba, Saskatchewan, and New York regions experienced resources slightly higher than long-term averages, producing between 2 - 3% above long-term average resources. The Western region experienced resources at long-term averages while the Ontario region experienced resources 10% below long-term averages.

For the year ended December 31, 2011, revenue from energy sales in the Renewable Energy division totalled $87.6 million, as compared to $80.1 million during the same period in 2010, an increase of $7.5 million or 9%. As the purchase of energy by AES is a significant driver of revenue and component of variable operating expenses, the division compares 'net energy sales' (energy sales revenue less energy purchases) as a more appropriate measure of the division's sales results. For the year ended December 31, 2011, net revenue from energy sales in the Renewable Energy division totalled $83.8 million, as compared to $75.1 million during the same period in 2010, an increase of $8.7 million or 12%.

Revenue generated from APCo's Ontario, Quebec and Western regions increased by $4.8 million due to a 15% overall increase in hydrology and $1.1 million due to an increase in weighted average energy rates, primarily in the Quebec region, of approximately 3% as compared to the same period in 2010. Revenue from APCo's New England and New York region facilities increased $1.8 million due to increased average hydrology partially offset by $1.1 million due to a decrease in weighted average energy rates of approximately 15%. Revenue from the Manitoba region increased $2.7 million primarily due to a stronger wind resource and $0.4 million due to an increase in weighted average energy rates. Revenue in the Maritime region increased $0.5 million, primarily due to increased customer demand as compared to the same period in 2010. These increases were partially offset by a $1.4 million decrease in revenue at AES primarily due to decreased energy rates as compared to the same period in 2010. Revenue at AES primarily consists of wholesale deliveries to local electric utilities and retails sales to commercial and industrial customers in Northern Maine ($11.6 million) and merchant sales of production in excess of customer demand and other revenue ($2.3 million). The division reported decreased revenue of $1.0 million from U.S. operations as a result of the weaker U.S. dollar as compared to the same period in 2010.

Red Lily I achieved commercial operations effective February 23, 2011. From the commercial operation date through December 31, 2011 Red Lily I produced 68.0 GWhrs of electricity. APCo's economic return from its investment in Red Lily currently comes in the form of interest payments, fees and other charges. Under the terms of the agreements, APCo has the right to exchange these contractual and debt interests in Red Lily for a direct 75% equity interest in 2016. For the year ended December 31, 2011, APCo earned fees and interest payments from Red Lily I in the total amount of $3.5 million.

For the year ended December 31, 2011, energy purchase costs by AES totalled $3.8 million. During this same period, AES purchased approximately 45.5 GWhrs of energy at market and fixed rates averaging U.S. $84 per MWhr. The Maritime region generated approximately 80% of the load required to service its customers as well as AES' customers in the year ended December 31, 2011. The division reported decreased energy purchase costs of $0.2 million as a result of the weaker U.S. dollar as compared to the same period in 2010.

For the year ended December 31, 2011, operating expenses excluding energy purchases totalled $26.1 million, as compared to $24.4 million during the same period in 2010, an increase of $1.7 million or 7%. Operating expenses were impacted by $0.9 million related to increased operating costs associated with the Tinker Assets and AES, primarily the result of higher production levels in the Maritime region as compared to the same period in 2010. These increases were partially offset by reduced operating expenses of approximately $0.6 million at the hydroelectric facilities. Operating expenses include costs incurred in the period of $1.9 million associated with the pursuit of various growth and development activities, an increase of $0.7 million as compared to the same period in 2010. In the prior period, APCo recorded a reduction in the development costs due to a reimbursement of $0.9 million in connection with the Red Lily I wind project. The division reported decreased expenses of $0.5 million from U.S. operations as a result of the weaker U.S. dollar as compared to the same period in 2010.

For the year ended December 31, 2011, interest and other income totalled $2.1 million, as compared to $0.8 million during the same period in 2010. Interest and other income primarily consists of interest related to the senior and subordinated senior debt interest in the Red Lily I project. This amount is included as part of APCo's earnings from its investment in Red Lily, as discussed above.

For the year ended December 31, 2011, Renewable Energy's operating profit totalled $62.1 million, as compared to $53.5 million during the same period of 2010, representing an increase of $8.6 million or 16%. For the year ended December 31, 2011, Renewable Energy's operating profit exceeded APCo's expectations primarily due to increased hydrology and wind resources in the Canadian regions.

2011 Fourth Quarter Operating Results

For the quarter ended December 31, 2011, the Renewable Energy division produced 353.5 GWhrs of electricity, as compared to 305.3 GWhrs produced in the same period in 2010, an increase of 16%. The increased generation is due to improved average wind generation in the quarter as compared to the comparable period in 2010. This level of production in 2011 represents sufficient renewable energy to supply the equivalent of 79,000 homes on an annualized basis with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 194,000 tons of CO_2 gas was prevented from entering the atmosphere in the fourth quarter of 2011.

During the quarter ended December 31, 2011, the division generated electricity equal to 111% of long-term projected average resources (wind and hydrology) as compared to 90% during the same period in 2010. In the fourth quarter of 2011, the New England region experienced resources significantly higher than long-term averages, producing 175% above long-term average resources, while the Manitoba, Saskatchewan, and Maritimes regions experienced resources higher than long-term averages, producing between 15 - 20% above long-term average resources. The Quebec region experienced resources above long-term averages, producing approximately 10% above long-term average resources. The Ontario, Western and New York regions experienced resources between 5 - 10% below long-term averages.

For the quarter ended December 31, 2011, revenue from energy sales in the Renewable Energy division totalled $23.8 million, as compared to $21.9 million during the same period in 2010, an increase of $1.9 million or 9%. As the purchase of energy by AES is a significant driver of revenue and component of variable operating expenses, the division compares 'net energy sales' (energy sales revenue less energy purchases) as a more appropriate measure of the division's sales results. For the quarter ended December 31, 2011, net revenue from energy sales in the Renewable Energy division totalled $23.1 million, as compared to $21.4 million during the same period in 2010, an increase of $1.7 million or 8%.

Revenue generated from APCo's Ontario, Quebec and Western regions increased by $0.5 million primarily due to a combination of an increase in weighted average energy rates of approximately 1% and a 5% overall increase in hydrology, primarily in the Ontario region as compared to the same period in 2010. Revenue from APCo's New England and New York region facilities increased $0.6 million primarily due to an increase of approximately 35% in average hydrology, offset by $0.6 million due to a decrease in weighted average energy rates of approximately 30% as compared to the same period in 2010. Revenue in the Maritime region decreased $0.3 million, primarily due to lower merchant sales of excess energy as compared to the same period in 2010. AES experienced a $0.2 million increase in revenue primarily due to increased average energy rates as compared to the same period in 2010. Revenue at AES primarily consists of wholesale deliveries to local electric utilities and retails sales to commercial and industrial customers in Northern Maine ($2.3 million) and merchant sales of production in excess of customer demand and other revenue ($0.9 million). Revenue from the Manitoba region increased $1.5 million due to an increased wind resource and $0.2 million due to an increase in weighted average energy rates as compared to the same period in 2010. The division reported decreased revenue of $0.1 million from U.S. operations as a result of the weaker U.S. dollar as compared to the same period in 2010.

In the quarter ended December 31, 2011 Red Lily I produced 27.7 GWhr of electricity which was sold to SaskPower. APCo's economic return from its investment in Red Lily currently comes in the form of interest payments, fees and other charges. For the three months ended December 31, 2011, APCo earned fees and interest payments from Red Lily in the total amount of $0.7 million.

For the quarter ended December 31, 2011, energy purchase costs by AES totalled $0.7 million as compared to $0.4 million during the same period in 2010. During the quarter, AES purchased approximately 13.1 GWhr of energy at market and fixed rates averaging U.S. $54 per MWhr. The Maritime region generated approximately 70% of the load required to service its customers as well as AES's customers in the three months ended December 31, 2011.

For the quarter ended December 31, 2011, operating expenses excluding energy purchases totalled $7.9 million, as compared to $7.0 million during the same period in 2010, an increase of $0.9 million or 13%. Operating expenses were impacted by a $0.3 million increase in operating costs at Canadian hydroelectric

facilities, primarily resulting from increased variable operating costs tied to higher production, partially offset by a decrease of $0.3 million related to decreased operating costs associated with the Tinker Assets as compared to the same period in 2010. Operating expenses include costs incurred in the period of $1.2 million associated with the pursuit of various growth and development activities, an increase of $0.5 million as compared to the same period in 2010. The division reported decreased expenses of $0.1 million from U.S. operations as a result of the weaker U.S. dollar as compared to the same period in 2010.

For the quarter ended December 31, 2011, interest and other income totalled $0.6 million, as compared to $0.2 million during the same period in 2010. Interest and other income primarily consists of interest related to the senior and subordinated senior debt interest in the Red Lily I project. This amount is included as part of APCo's earnings from its investment in Red Lily, as discussed above.

For the quarter ended December 31, 2011, Renewable Energy's operating profit totalled $16.1 million, as compared to $15.1 million during the same period of 2010, representing an increase of $1.0 million or 7%. For the quarter ended December 31, 2011, Renewable Energy's operating profit exceeded APCo's expectations primarily due to stronger hydrology and wind generation in both the U.S. and Canadian regions.

Divisional Outlook – Renewable Energy

The APCo Renewable Energy division is expected to perform based on long-term average resource conditions for hydrology and long-term average wind resources in the first quarter of 2012.

AES anticipates that, based on the expected load forecast for its existing contracts, it will provide approximately 35,000 MWhrs of energy to its customers in the first quarter of 2012. AES anticipates that APCo owned assets will provide 43% of the energy required to service its customers in the first quarter of 2012 and that it will need to purchase approximately 20,000 MWhrs of energy from the ISO NE or similar market. AES has in place fixed price financial energy contracts to operationally hedge the price of the customer supply obligations which are not expected to be supplied by APCo owned assets and to minimize the volatility of the energy prices. These contracts in combination with the expected production from APCo owned assets are used to balance the monthly customer load.

APCo: Thermal Energy Division

	Three months ended December 31		Year ended December 31	
	2011	**2010**	**2011**	**2010**
Performance (GW-hrs sold)	**126.5**	120.6	**517.0**	465.4
Performance (tonnes of waste processed)	**42,145.0**	43,535.0	**166,825.0**	90,690.0
Performance (steam sales – billions lbs)	**308.4**	315.6	**1,209.4**	1,180.0
Revenue				
Energy/steam sales	**$ 10,582**	$ 11,506	**$ 46,666**	$ 49,860
Less:				
Cost of Sales – Fuel *	**(5,694)**	(5,492)	**(22,896)**	(22,348)
Net Energy/steam Sales Revenue	**$ 4,888**	$ 6,014	**$ 23,770**	$ 27,512
Waste disposal sales	**4,046**	4,164	**16,406**	9,039
Other revenue	**541**	311	**1,352**	1,209
Total net revenue	**$ 9,475**	$ 10,489	**$ 41,528**	$ 37,760
Expenses				
Operating expenses *	**(5,449)**	(5,492)	**(21,589)**	(21,469)
Interest and other income	**(74)**	100	**(6)**	633
Division operating profit (including interest and dividend income)	**$ 3,952**	$ 5,097	**$ 19,933**	$ 16,924

* Cost of Sales - Fuel consists of natural gas and fuel costs at the Sanger and Windsor Locks facilities. Under GAAP, in APUC's consolidated Financial Statements, these amounts are included in operating expenses.

2011 Annual Operating Results

For the year ended December 31, 2011, the Thermal Energy Division produced 517.0 GW-hrs of energy as compared to 465.4 GW-hrs of energy in the comparable period of 2010. During the year ended December 31, 2011, the business unit's total production increased by 52.4 GWhr from the Windsor Locks facility and 6.1 GWhr from the EFW facility as compared to the same period in 2010. The comparable period includes 2.5 GWhr of production from landfill gas facilities which ceased generating energy and were closed in 2010.

The EFW facility processed 166,825 tonnes of municipal solid waste in 2011 as compared to 90,690 tonnes processed in the same period of 2010. The EFW facility processed waste for a full 12 month period in 2011 as compared to a 6 month period in 2010 when from January to July 2010 the facility was shut down as it underwent an extensive refurbishment. The current level of production resulted in the diversion of approximately 120,000 tonnes of waste from municipal solid waste landfill sites in the year ended December 31, 2011.

During the year ended December 31, 2011, the BCI and Windsor Locks facilities sold approximately 1,200 billion lbs of steam as compared to approximately 1,200 billion lbs of steam in the comparable period of 2010. During the year ended December 31, 2011, operations at the EFW facility generated 508 billion lbs of steam for the BCI facility as compared to 272 billion lbs of steam in the same period in 2010.

For the year ended December 31, 2011, energy / steam revenue in the Thermal Energy division totalled $46.7 million, as compared to $49.9 million during the same period in 2010, a decrease of $3.2 million, or 6%. As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales revenue' (energy sales revenue less natural gas expense) as a more appropriate measure of the division's results. For the year ended December 31, 2011, net energy / steam sales revenue at the Thermal Energy division totalled $23.8 million, as compared to $27.5 million during the same period in 2010, a decrease of $3.7 million, primarily arising from the weaker U.S. dollar and the power purchase agreement that concluded in April 2010 at the Windsor Locks facility.

The overall decrease in revenue from energy / steam sales was primarily due to a decrease of $5.7 million at the Windsor Locks facility as a result of decreased average energy rates, in part due to the change in operating model of the facility as it came off contract, partially offset by an increase of $4.8 million as a result of increased production, as compared to the prior year. The Sanger facility experienced a net decrease of $0.6 million as a result of decreased energy pricing, in part due to lower average landed price per mmbtu for natural gas, partially offset by $0.2 million as a result of increased production. Energy / steam sales revenue decreased $0.3 million in the period as a result of the closure of the LFG facilities, as compared to the prior year. The decrease in revenue was partially offset by $0.3 million at the BCI and EFW facilities as a result of increased production of energy and steam, as compared to the same period in 2010. The natural gas expense at the Sanger and Windsor Locks facilities is discussed in detail below. The division reported decreased energy sales revenue of $1.7 million from operations as a result of the weaker U.S. dollar, as compared to the same period in 2010.

Revenue from waste disposal sales for the year ended December 31, 2011 totalled $16.4 million, as compared to $9.0 million during the same period in 2010. The increase was a result of the EFW facility refurbishment from January to July 2010 in the comparable period of 2010.

For the year ended December 31, 2011, fuel costs at Sanger and Windsor Locks totalled $22.9 million, as compared with $22.3 million in the same period in 2010, an increase of $0.5 million. 1 The overall natural gas expense at the Windsor Locks facility increased U.S. $1.7 million (10%), primarily the result of a 10% increase in volume of natural gas consumed, as compared to the same period in 2010. The average landed cost of natural gas at the Windsor Locks facility during the year was U.S. $4.84 per mmbtu. This was partially offset by a decrease in the natural gas expense at Sanger of U.S. $0.3 million (5%), primarily the result of a 8% decrease in the average landed cost of natural gas per mmbtu as compared to the same period in 2010. The average landed cost of natural gas at the Sanger facility during the year was U.S. $4.42 per mmbtu. The division reported decreased fuel expenses of $0.8 million as a result of the weaker U.S. dollar as compared to the same period in 2010.

For the year ended December 31, 2011, operating expenses, excluding fuel costs at Windsor Locks and Sanger, totalled $21.6 million, as compared to $21.5 million during the same period in 2010, an increase of $0.1 million. The increase in operating expenses in the year was primarily due to $4.4 million in increased gas, consumables, repair and maintenance and wages at the EFW facility resulting from the outage at the facility in 2010, partially offset by $0.6 million in reduced operating costs at Windsor Locks, $2.0 million at BCI, primarily

[1] APCo's Sanger and Windsor Locks generation facilities purchase natural gas from different suppliers and at prices based on different regional hubs. Consequently the average landed cost per unit of natural gas will differ between facility and regional changes in the average landed cost for natural gas may result in one facility showing increasing costs per unit while the other showing decreasing costs, as compared to the same period in the prior year. Total natural gas expense will vary based on the volume of natural gas consumed and the average landed cost of natural gas for each mmbtu. As a result, a facility may record a higher aggregate expense for natural gas as a result of a lower average landed per unit cost for natural gas combined with a consumption of a higher volume of such gas.

the result of reduced natural gas costs due to the EFW facility generating more steam and $0.7 million of reduced operating costs as a result of the closure of the land-fill gas facilities in 2010, as compared to the same period in 2010. Operating expenses in the included costs of $0.4 million associated with the pursuit of various growth and development activities as compared to $0.5 million in the comparable period. The division reported decreased expenses of $0.5 million from U.S. operations as a result of the weaker U.S. dollar as compared to the same period in 2010.

For the year ended December 31, 2011, the Thermal Energy division's operating profit totalled $19.9 million, as compared to $16.9 million during the same period in 2010, representing an increase of $3.0 million or 18%. Operating profit in the Thermal Energy division exceeded expectations for the year ended December 31, 2011 as a result of improved operations at the EFW facility.

2011 Fourth Quarter Operating Results

During the quarter ended December 31, 2011, the business unit produced 126.5 GWhr of energy as compared to 120.6 GWhr of energy in the comparable period of 2010. During the quarter ended December 31, 2011, the business unit's total production increased by 8.0 GWhr from the Windsor Locks facility, partially offset by a decline of 1.6 GWhr from the Sanger facility, as compared to the same period in 2010.

The EFW facility processed 42,145 tonnes of municipal solid waste as compared to 43,535 tonnes of municipal solid waste in the same period of 2010. The current level of production resulted in the diversion of approximately 30,400 tonnes of waste from municipal solid waste landfill sites in the fourth quarter of 2011.

During the quarter ended December 31, 2011, the BCI and Windsor Locks facilities sold 310 billion lbs of steam as compared to 320 billion lbs of steam in the comparable period of 2010. During the quarter ended December 31, 2011, operations at the EFW facility generated 129 billion lbs of steam for the BCI facility as compared to 144 billion lbs of steam in the same period in 2010.

For the quarter ended December 31, 2011, energy / steam revenue in the Thermal Energy division totalled $10.6 million, as compared to $11.5 million during the same period in 2010, a decrease of $0.9 million, or 8%. As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales revenue' (energy sales revenue less natural gas expense) as a more appropriate measure of the division's results. For the quarter ended December 31, 2011, net energy / steam sales revenue at the Thermal Energy division totalled $4.9 million, as compared to $6.0 million during the same period in 2010, a decrease of $1.1 million, primarily due to the Windsor Locks facility selling energy into the ISO-NE day-ahead market as compared to in 2010 when facility derived revenues from participating in the Forward Reserve Market. The decision to have the facility not participate in the Forward Reserve Market in 2011 was due to the fact that the facility could earn more selling into the ISO-NE day-ahead market compared to the lower prices offered for participating the Forward Reserve Market in 2011.

The decrease in revenue from energy / steam sales was primarily due to a decrease of $1.3 million at the Windsor Locks facility as a result of decreased energy rates, in part due to a lower average landed price per mmbtu for natural gas and the change in operating model of the facility, partially offset by an increase of $0.7 million at the Windsor Locks facility due to increased production and a net decrease of $0.1 million at the Sanger facility as a result of the change in energy pricing and production as compared to the same period in 2010. The natural gas expense at the Sanger and Windsor Locks facilities is discussed in detail below.

Revenue from waste disposal sales for the quarter ended December 31, 2011 totalled $4.0 million, as compared to $4.2 million during the same period in 2010.

For the quarter ended December 31, 2011, fuel costs at Sanger and Windsor Locks totalled $5.7 million, as compared with $5.5 million in the same period in 2010, an increase of $0.2 million. The overall natural gas expense at the Windsor Locks facility increased $0.2 million (5%), primarily the result of a 11% increase in volume of natural gas consumed, partially offset by a 5% decrease in the average landed cost of natural gas per mmbtu as compared to the same period in 2010. The average landed cost of natural gas at the Windsor Locks facility during the quarter was $4.75 per mmbtu. This was partially offset by a decrease in the natural gas expense at Sanger of $0.1 million (10%), primarily the result of a 8% decrease in the average landed cost of natural gas per mmbtu and a 2% decrease in the volume of natural gas consumed as compared to the same period in 2010. The average landed cost of natural gas at the Sanger facility during the quarter was U.S. $4.03 per mmbtu. The division reported increased fuel costs of $0.1 million as a result of the stronger U.S. dollar as compared to the same period in 2010.

For the quarter ended December 31, 2011, operating expenses, excluding fuel costs at Windsor Locks and Sanger, totalled $5.4 million, as compared to $5.5 million during the same period in 2010, a decrease of $0.1 million.

For the quarter ended December 31, 2011, the Thermal Energy division's operating profit totalled $4.0 million, as compared to $5.1 million during the same period in 2010, representing a decrease of $1.1 million or 22%. Operating profit in the Thermal Energy division met overall expectations for the quarter ended December 31, 2011.

Divisional Outlook – Thermal Energy

APCo's Thermal Energy division's Sanger facility will be offline during the majority of the first quarter of 2012 to accommodate certain transmission system upgrades being undertaken by PG&E and to allow for planned major maintenance. During this period capacity payments from PG&E will continue, however energy sales will be curtailed during this period. As a result, revenues from the Sanger facility are expected to be approximately $1.3 million lower than revenues achieved in the first quarter of 2011.

The Windsor Locks natural gas fired cogeneration facility will continue to sell a portion of its electricity capacity and all of its steam capacity to the industrial host with the balance of the electrical capacity available to be sold either into the ISO NE day-ahead market or to industrial customers through AES. It is anticipated that performance during the first quarter of 2012 will be in line with expectations.

APCo has commenced the repowering project at the Windsor Locks facility and has entered into an agreement with the steam host that extends the steam supply agreement to 2027. See *APCo Development Division - Windsor Locks* for further discussion on the repowering project.

The EFW facility is expected to continue to perform at throughput and operating costs levels in the first quarter of 2012 consistent with the results experienced in 2011. Pursuant to the waste supply agreement with the Region, the EFW facility charges an initial rate for a base 127,900 tonnes per year of acceptable municipal solid waste in a contract year and, once the base throughput levels are exceeded, the facility charges a lower rate for municipal solid waste received in the remainder of the contract year. The facility exceeded the base throughput levels as of the end of 2011 and, as a result, APCo anticipates lower revenue from waste disposal sales of approximately $0.5 million in the first quarter of 2012 as compared to the first quarter of 2011 as the tip fee charged during January and February will be at the lower rate.

The EFW facility "tip or pay" waste supply agreement with the Region expires in April 2012. On February 23, 2012, the Peel Regional Council decided to seek competitive proposals from several waste management companies, including APCo. APCo is participating in this proposal process. In addition, the facility is currently permitted to accept commercial and industrial waste from certain other jurisdictions outside of the Region of Peel. APCo is actively sourcing alternative supply options with respect to municipal solid waste from other jurisdictions to ensure a continued supply of waste for the facility.

APCo: Development Division

The Development division works to identify, develop and construct new power generating facilities, as well as to identify, develop and construct other accretive projects that maximize the potential of APCo's existing facilities. The Development division is focused on projects within North America and is committed to working proactively with all stakeholders, including local communities. APCo's approach to project development 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 power purchase agreement, obtaining the required financing commitments to develop the project, completion of environmental permitting, and fixing the cost of the major capital components of the project. It is not until all major aspects of a project are secured that APCo will begin construction.

The Development division also creates opportunities through accretive acquisitions of operating assets and prospective projects that are at various stages of development.

Current Development Projects

APCo's Development Division has successfully advanced a number of projects and has been awarded or acquired a number of Power Purchase Agreements. The projects are as follows:

Project Name (Location)	Location	Size (MW)	Estimated Capital Cost	Commercial Operation	PPA Term	Production GWhr
Chaplin Wind [1]	Saskatchewan	177	$ 355.0	2016	25	720.0
Amherst Island [2]	Ontario	75	$ 230.0	2014	25	247.0
Morse Wind [3, 4]	Saskatchewan	25	$ 70.0	2014	20	93.0
St. Damase [1]	Quebec	24	$ 70.0	2013	20	86.0
Val Eo [1]	Quebec	24	$ 70.0	2015	20	66.0
St. Leon II [1]	Manitoba	17	$ 30.0	2012	25	58.0
Cornwall Solar [1, 2]	Ontario	10	$ 45.0	2013	20	13.4
Total		**352**	**$ 870.0**			**1,283.4**

Notes:
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").

Chaplin Wind

Subsequent to the year end, APCo entered into a 25 year Power Purchase Agreement 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 power purchase agreement 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.

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 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 project is currently contemplated to use efficient Class III wind turbine generator technology. APCo forecasts that the available wind resource could produce approximately 247 GWhr 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 submission of the renewable energy application is targeted for the summer of 2012. Construction will commence shortly following the approval of the application and is expected to take 12 to 18 months.

Morse Wind Project

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

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 for award of PPAs in accordance with the SaskPower Green Options Partners Program. The two 10 MW PPA's were awarded in May 2010 and the 5 MW PPA was awarded in June 2011. Upon SaskPower's approval and execution of the Kineticor PPAs, Kineticor will then assign the PPAs to APCo. All three of the projects are expected to be completed contemporaneously in early 2014.

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.

Quebec Community Wind Projects

In 2010, APCo worked with Société en Commandite Val-Éo, a community cooperative with a development project located in the Lac Saint-Jean region of Quebec, and the community of Saint-Damase to submit proposals into Hydro Quebec's 250 MW wind Request for Proposal. On December 20, 2010, both projects were awarded power purchase contracts that stipulate the use of ENERCON wind turbines.

Saint-Damase

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. The first 24 MW phase of the project is expected to be comprised of eight to twelve generators (depending on capacity of the selected wind turbine model), producing approximately 86,000 MWhr annually. Construction of the first 24 MW phase of the project is estimated to begin in early 2013 with a commercial operations date in late 2013.

The interest of APUC in the project is subject to final negotiations with the municipality but, in any event, 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 studies of flora and fauna and the public consultation process are ongoing. In July 2011, meetings were conducted with participating landowners in addition to an open house to obtain additional community feedback. All major environmental authorizations are targeted for completion by the end of 2012.

Val-Éo

The Val-Éo Wind Project is located in the local municipality of Saint-Gédéon de Grandmont, which is within the regional municipality of Lac-Saint-Jean-Est. The project proponents include the Val-Éo wind cooperative formed by community based landowners and APCo. The first 24 MW phase of the project is expected to be comprised of eight generators, producing approximately 66,000 MWhr annually. Construction of the first 24 MW phase of the project is expected to begin in early 2015 with commercial operations occurring in late 2015.

The interest of APUC in the project is subject to final negotiations with the 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 met, 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 with all major authorizations targeted for completion by the end of 2012.

St. Leon II

In July 2011, APCo executed a 25-year power purchase agreement with Manitoba Hydro in respect of St. Leon II (a 16.5 MW expansion of APUC's existing St. Leon wind energy project located in the Province of Manitoba). Construction of this project commenced on August 30, 2011 using 10 Vestas V82 turbines. The final turbine was erected in February 2012 and the project is generating energy on all units as of March 1, 2012. The project is expected to achieve commercial operation in the second quarter of 2012. The total capital cost of the project is expected to be $29.5 million.

Cornwall Solar

APCo entered into a share purchase agreement with EffiSolar Energy Corporation ("EffiSolar"), to acquire all of the issued and outstanding shares of Cornwall Solar Inc. based upon the achievement of specific milestones. On December 30, 2011 OPA approval was received and the transaction closed on January 4, 2012. Cornwall Solar owns the rights to develop a 10 MWac solar project located near Cornwall, Ontario. In addition to the Cornwall project, APCo has acquired an option to acquire 10 additional Ontario based solar projects. Projects in the FIT Pipeline have submitted Feed-in-Tariff applications for an additional 100MWac.

The Project has been granted an Ontario FIT contract by the OPA, with a 20 year term and a rate of $443/MWhr, resulting in expected initial annual revenues of approximately $6.2 million. The Project contemplates the use of a ground-mounted PV array system, with expected annual generation of approximately 13,400 MWh, enough to provide electricity to approximately 1,000 homes.

Following the completion of all regulatory submissions and approvals, construction of the project is expected to begin in the second half of 2012, with a Commercial Operation Date estimated in early 2013. The Project is being developed on two parcels of leased land totalling approximately 138 acres.

Total capital cost of the project is targeted at approximately $45 million, which amount includes 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.

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 extension of the ESA with Ahlstrom, the extended term continues until 2027, and supports the installation of a new 14 MW Solar Titan combustion gas turbine which is more appropriately sized to meet the electrical and steam requirements of the steam host. The new cogeneration equipment is in construction with commercial operation expected in July 2012. The total expected capital cost for this project is estimated at approximately U.S. $25 million. APCo believes it is eligible to receive a one-time non-recurring grant from the State of Connecticut equivalent to U.S. $450/KW to a maximum of U.S. $6.6 million which would offset the cost of such re-powering. An additional benefit of the State of Connecticut grant program is that local distribution charges for natural gas used by the new turbine are waived, with an estimated benefit to the Windsor Locks facility of approximately U.S. $500,000/year. In addition to installing the new gas turbine, APCo would expect to continue to operate the existing electrical generating equipment in the ISO NE market when it is commercially profitable to do so. APCo also believes that this project would qualify for a combined heat and power investment tax credit ("ITC") sponsored by the U.S. Federal Government. The benefit of the ITC grant is approximately U.S. $1 million in addition to the Connecticut DPUC grant would offset the cost of such re-powering.

Liberty Utilities
WATER | GAS | ELECTRIC

Liberty Utilities' business strategy is to operate and grow its nationwide portfolio of rate regulated water, natural gas and electric distribution and wastewater collection and treatment utilities and electric transmission assets, sharing certain common infrastructure between utilities to support best-in-class customer care for all utility ratepayers and building constructive regulatory relationships in the jurisdictions in which it operates.

As a result of the current and expected growth, Liberty Utilities has elected to organize the management of its utility operations by geographic region rather than by line of business. This approach will also enhance

operational efficiencies and garner greater economies of scale while preserving the customer and regulator focus of the businesses which arises from the independent operations of these regions. As a result of this change Liberty Utilities now has two separately managed regions - Liberty Utilities (South) (formerly known as Liberty Water) and Liberty Utilities (West) (formerly known as Liberty Energy - Calpeco).

As the currently committed growth initiatives are completed, additional management regions will be created. Liberty Utilities (East) will be formed initially to deliver electrical and natural gas distribution services following the acquisition of Granite State and EnergyNorth. A fourth management region, Liberty Utilities (Central), will initially be created to manage the delivery of Liberty Utilities services in Missouri, Illinois and Iowa following the acquisition of certain gas distribution assets from Atmos.

Liberty Utilities is committed to being a leading utility provider of water, natural gas and electric utility services while providing stable and predictable earnings to APUC from its utility operations. Liberty Utilities has presented the division's results in both the reporting currency and its functional currency. Liberty Utilities believes that since the division's operations are entirely in the U.S., it is useful to show the results in Liberty Utilities' functional currency without the impact of foreign exchange.

Liberty Utilities (South)

Liberty Utilities (South) operates in Arizona, Texas, Missouri and Illinois and currently provides rate regulated water and wastewater utility services to approximately 76,000 customers in those states.

	Year ended December 31		Year ended December 31	
	2011	**2010**	**2011**	**2010**
Number of				
Wastewater connections			**36,750**	35,420
Wastewater treated (millions of gallons)			**2,000**	2,000
Water distribution connections			**38,750**	37,666
Water sold (millions of gallons)			**5,600**	5,500
	U.S. $	U.S. $	**Can $**	Can $
NBV of Assets for regulatory purposes (U.S. $)	**155,763**	155,258		
Revenue				
Wastewater treatment	**$ 23,295**	$ 20,202	**$ 23,031**	$ 20,935
Water distribution	**21,574**	15,877	**21,330**	16,453
Other Revenue	**636**	601	**628**	623
	$ 45,505	$ 36,680	**$ 44,989**	$ 38,011
Expenses				
Operating expenses	**(22,959)**	(21,371)	**(22,720)**	(22,199)
Other income	**482**	154	**488**	149
Divisional operating profit	**$ 23,028**	$ 15,463	**$ 22,757**	$ 15,961

Liberty Utilities (South) is committed to being a leading utility provider of safe, high quality and reliable water and wastewater services while providing stable and predictable earnings from its utility operations. Liberty Utilities (South) has presented the division's results in both the reporting currency and its functional currency. Liberty Utilities (South) believes that since the division's operations are entirely in the U.S., it is useful to show the results in Liberty Utilities (South)'s functional currency without the impact of foreign exchange.

Liberty Utilities (South) reports total connections, inclusive of vacant connections rather than customers. Liberty Utilities (South) had 36,750 wastewater connections as at December 31, 2011, as compared to 35,420 as at December 31, 2010, an increase of 1,330 in the period or 3.8%. Liberty Utilities (South) had 38,750 water distribution connections as at December 31, 2011, as compared to 37,666 as at December 31, 2010, representing an increase of 1,084 in the period or 2.8%. Total connections include approximately 1,800 vacant wastewater connections and 1,400 vacant water distributions connections as at December 31, 2011. Liberty Utilities (South)'s change in water distribution and wastewater treatment customer base during the period is primarily due to the acquisition of two small utilities in Missouri during the last quarter of 2011 and modest growth at Liberty Utilities (South)'s other facilities.

Liberty Utilities (South) has investments in regulatory assets of U.S. $155.8 million across four states as at December 31, 2011, as compared to U.S. $155.3 million as at December 31, 2010.

2011 Annual Operating Results

During the year ended December 31, 2011, Liberty Utilities (South) provided approximately 5.6 billion U.S. gallons of water to its customers, treated approximately 2.0 billion U.S. gallons of wastewater and sold approximately 270 million U.S. gallons of treated effluent.

For the year ended December 31, 2011, Liberty Utilities (South)'s revenue totalled U.S. $45.5 million as compared to U.S. $36.7 million during the same period in 2010, an increase of U.S. $8.8 million or 24%. The increased revenues were primarily due to the implementation of rate increases from rate cases filed with state regulators over the past two years. Rate cases ensure that a particular facility has the opportunity to recover its operating costs and earn a fair and reasonable return on its capital investment as allowed by the regulatory authority under which the facility operates.

Revenue from water distribution totalled U.S. $21.6 million as compared to U.S. $15.8 million during the same period in 2010, an increase of U.S. $5.7 million or 36%. The annual water distribution revenue was impacted, primarily due to the implementation of rate increases of U.S. $3.9 million at the Litchfield Park Service Company ("LPSCo") facility, U.S. $1.0 million at the Rio Rico facility and U.S. $0.8 million at the Bella Vista facility as compared to the same period in 2010.

Revenue from wastewater treatment totalled U.S. $23.3 million, as compared to U.S. $20.2 million during the same period in 2010, an increase of U.S. $3.1 million or 15%. The annual wastewater treatment revenue was impacted by increased revenue, primarily due to the implementation of rate increases of U.S. $2.8 million at the LPSCo facility and U.S. $0.4 million at the Black Mountain facility, partially offset by lower revenue at the Rio Rico facility of $0.4 million, as compared to the same period in 2010. In addition, revenue increased U.S. $0.4 million at seven wastewater treatment facilities, primarily due to customer increases at the Tall Timbers facility as compared to the same period in 2010.

For the year ended December 31, 2011, operating expenses totalled U.S. $23.0 million, as compared to U.S. $21.4 million during the same period in 2010, an increase of U.S. $1.6 million or 7%. Operating expenses increased due to increased utilities, consumable, property tax and insurance expenses of U.S. $0.5 million and U.S. $1.0 million related to increased wages, salary and other operating costs as compared to the same period in 2010.

For the year ended December 31, 2011, Liberty Utilities (South)'s operating profit totalled U.S. $23.0 million as compared to U.S. $15.5 million in the same period in 2010, an increase of U.S. $7.6 million or 49%. Liberty Utilities (South)'s operating profit exceeded expectations for the year ended December 31, 2011 due to increased customer counts and lower than expected power and operating labour costs.

Measured in Canadian dollars, for the year ended December 31, 2011, Liberty Utilities (South)'s revenue totalled $45.0 million as compared to $38.0 million during the same period in 2010, an increase of $7.0 million. Revenue from wastewater treatment totalled $23.0 million, as compared to $20.9 million during the same period in 2010, an increase of $2.1 million. Revenue from water distribution totalled $21.3 million, as compared to $16.5 million during the same period in 2010, an increase of $4.9 million. Liberty Utilities (South) reported decreased revenue from operations of $1.9 million in 2011 as a result of the weaker U.S. dollar as compared to the same period in 2010.

Measured in Canadian dollars, for the year ended December 31, 2011, operating expenses totalled $22.7 million, as compared to $22.2 million during the same period in 2010, an increase of $0.5 million. Liberty Utilities (South) reported lower expenses from operations of $1.2 million as a result of the weaker U.S. dollar, as compared to the same period in 2010.

For the year ended December 31, 2011, Liberty Utilities (South)'s operating profit totalled $22.8 million as compared to $16.0 million in the same period in 2010, an increase of $6.8 million.

	Three months ended December 31		Three months ended December 31	
	2011	2010	2011	2010
Number of				
Wastewater treated (millions of gallons)			**500**	500
Water sold (millions of gallons)			**1,300**	1,400
	U.S. $	U.S. $	**Can $**	Can $
Revenue				
Wastewater treatment	**5,855**	5,543	**5,993**	5,649
Water distribution	**5,223**	4,074	**5,347**	4,152
Other Revenue	**123**	205	**126**	208
	$ 11,201	$ 9,822	**$ 11,466**	$ 10,009
Expenses				
Operating expenses	**(5,901)**	(5,264)	**(6,039)**	(5,370)
Other income	**229**	152	**224**	81
Divisional operating profit	**$ 5,529**	$ 4,710	**$ 5,651**	$ 4,720

2011 Fourth Quarter Operating Results

During the quarter ended December 31, 2011, Liberty Utilities (South) provided approximately 1.3 billion U.S. gallons of water to its customers, treated approximately 500 million U.S. gallons of wastewater and sold approximately 35 million U.S. gallons of treated effluent.

For the quarter ended December 31, 2011, Liberty Utilities (South)'s revenue totalled U.S. $11.2 million as compared to U.S. $9.8 million during the same period in 2010, an increase of U.S. $1.4 million or 14%. The increased revenues were primarily due to the implementation of rate increases from rate cases filed with state legislators over the past two years.

Revenue from water distribution totalled U.S. $5.2 million, as compared to U.S. $4.1 million during the same period in 2010, an increase of U.S. $1.1 million or 28%. The fourth quarter water distribution revenue increased primarily due to the implementation of rate increases of U.S. $0.6 million at the LPSCo facility, U.S. $0.3 million at the Rio Rico facility and U.S. $0.3 million at the Bella Vista facility as compared to the same period in 2010.

Revenue from wastewater treatment totalled U.S. $5.9 million, as compared to U.S. $5.5 million during the same period in 2010, an increase of U.S. $0.3 million or 6%. The fourth quarter wastewater treatment revenue increased primarily from the implementation of rate increases of U.S. $0.5 million at the LPSCo facility and U.S. $0.2 million at ten wastewater treatment facilities primarily due to increased customers as compared to the same period in 2010.

For the quarter ended December 31, 2011, operating expenses totalled U.S. $5.9 million, as compared to U.S. $5.3 million during the same period in 2010. Overall expenses increased U.S. $0.6 million or 12% as compared to the same period in 2010. Operating expenses increased due to increased utilities, consumable, property tax and insurance expenses of U.S. $0.1 million and U.S. $0.4 million related to wages, salary and other operating costs as compared to the same period in 2010.

For the quarter ended December 31, 2011, Liberty Utilities (South)'s operating profit totalled U.S. $5.5 million as compared to U.S. $4.7 million in the same period in 2010, an increase of U.S. $0.8 million or 17%. Liberty Utilities (South)'s operating profit met expectations for the three months ended December 31, 2011.

Measured in Canadian dollars, for the quarter ended December 31, 2011, Liberty Utilities (South)'s revenue totalled $11.5 million, as compared to $10.0 million during the same period in 2010. Revenue from wastewater treatment totalled $6.0 million, as compared to $5.6 million during the same period in 2010, an increase of $0.3 million. Revenue from water distribution totalled $5.3 million, as compared to $4.2 million in the same period in 2010, an increase of $1.2 million. Liberty Utilities (South) reported increased revenue from operations of $0.1 million in the fourth quarter of 2011 as a result of the stronger U.S. dollar as compared to the same period in 2010.

Measured in Canadian dollars, for the quarter ended December 31, 2011, operating expenses totalled $6.0 million, as compared to $5.4 million during with same period in 2010, an increase of $0.6 million. Liberty Utilities (South) reported lower expenses from operations of $0.4 million as a result of the weaker U.S. dollar, as compared to the same period in 2010.

For the quarter ended December 31, 2011, Liberty Utilities (South)'s operating profit totalled $5.7 million as compared to $4.7 million in the same period in 2010, an increase of $0.9 million. Liberty Utilities (South)'s operating profit met expectations for the three months ended December 31, 2011.

Outlook – Liberty Utilities (South)

Liberty Utilities (South) expects continuing modest customer growth throughout its service territories in 2012.

Revenue increases from rate cases at the Rio Rico facility and the Bella Vista facility completed in the first quarter of 2011 are anticipated to contribute moderate additional revenue in Liberty Utilities (South) in the first quarter of 2012 as compared to the same period in 2011. Liberty Utilities (South) attributes the majority of the revenue increases in the year ended December 31, 2011 to the impact of completed rate cases.

Liberty Utilities (West)

On January 1, 2011, APUC, in partnership with Emera, acquired the assets comprising the California Utility for a gross purchase price of approximately U.S. $136.1 million. Liberty Utilities owns 50.001% and Emera owns 49.999% of California Pacific Utility Ventures LLC, which owns 100% of the purchaser of the California Utility, California Pacific Electric Company ("Calpeco").

The acquisition of the California Utility was completed following receipt of all U.S. state and federal regulatory approvals. Contemporaneously with the closing, Emera exchanged previously announced subscription receipts into 8.532 million APUC common shares at a purchase price of $3.25 per share. The proceeds of the subscription receipts were utilized to fund Liberty Energy's share of the equity in acquisition of the California Utility.

The acquisition was also funded in part with the proceeds of a U.S. $70 million senior unsecured notes. The notes are a senior unsecured private placement with U.S. institutional investors. The notes are fixed rate and split into two tranches, U.S. $45 million of ten year 5.19% notes maturing December 29, 2020 and U.S. $25 million of 5.59% fifteen year notes maturing December 29, 2025.

Liberty Utilities (West) operates in California and currently provides local electrical distribution utility services to approximately 47,000 customers located in the Lake Tahoe region.

	Year ended December 31		Year ended December 31	
	2011	**2010**	**2011**	**2010**
Number of Customer Accounts				
Residential			41,346	—
Commercial – Small			5,506	—
Commercial – Large			54	—
Total Customer Accounts			**46,906**	
Customer Usage (GWhr)				
Residential			291.2	—
Commercial – Small			174.2	—
Commercial – Large			136.6	—
Total Customer Usage (GWhr)			**602.0**	
	U.S. $	U.S. $	**Can $**	Can $
Assets for regulatory purposes (U.S. $)	**155,843**	—		
Revenue				
Utility energy sales and distribution	**$ 78,125**	$ —	**$ 77,368**	$ —
Less:				
Cost of sales – Energy*	**(46,917)**	—	**(46,491)**	
Net utility energy sales	**$ 31,208**	$ —	**$ 30,877**	$ —
Expenses				
Operating expenses	**(16,142)**	—	**(16,019)**	—
Division operating profit**	**$ 15,066**	$ —	**$ 14,858**	$ —

* Cost of Sales - Energy consists of energy purchases. Under GAAP, in APUC's consolidated Financial Statements, these amounts are included in operating expenses.

** Represents 100% of investment in the California Utility.

As at December 31, 2011, Liberty Utilities (West) holds a 50.001% controlling interest in the California Utility. As the California Utility was acquired on January 1, 2011 there are no comparable results for 2010.

Liberty Utilities reports active connections, exclusive of vacant connections rather than total connections. Liberty Utilities (West) had approximately 41,300 residential electrical customer accounts and 5,550 commercial electrical customer accounts, as at December 31, 2011.

Liberty Utilities (West) has investments in regulatory assets of U.S. $155.8 million in California as at December 31, 2011.

2011 Annual Operating Results

During the year ended December 31, 2011, Liberty Utilities (West)'s customer usage totalled approximately 602,000 MWhr of energy.

For the year ended December 31, 2011, Liberty Utilities (West)'s revenue from utility energy sales totalled U.S. $78.1 million. The purchase of energy by the California Utility is a significant revenue driver and component of operating expenses but these costs are ultimately passed through to its customers. As a result, the division compares 'net energy sales revenue' (energy sales revenue less energy purchases) as a more appropriate measure of the division's results. For the year ended December 31, 2011, net utility energy sales revenue for Liberty Utilities (West) totalled U.S. $31.2 million.

For the year ended December 31, 2011, energy purchases for Liberty Utilities (West) totalled U.S $46.9 million. During the year ended December 31, 2011, the California Utility purchased approximately 602,000 MWhr of energy at rates averaging U.S. $77.9 per MWhr.

For the year ended December 31, 2011, operating expenses, excluding energy purchases, totalled U.S. $16.1 million.

For the year ended December 31, 2011, Liberty Utilities (West)'s operating profit totalled U.S. $15.1 million. Liberty Utilities (West)'s operating profit did not meet expectations for the year ended December 31, 2011 primarily due to higher than budgeted insurance, administration and distribution costs which include vegetation management and maintenance, partially offset by lower than budgeted property taxes and higher than budgeted net utility energy sales.

Measured in Canadian dollars, for the year ended December 31, 2011, Liberty Utilities (West)'s revenue from energy sales totalled $77.4 million. For the year ended December 31, 2011, Liberty Utilities (West)'s net energy sales revenue totalled $30.9 million.

Measured in Canadian dollars, for the year ended December 31, 2011, Liberty Utilities (West)'s energy purchases totalled $46.5 million.

Measured in Canadian dollars, for the year ended December 31, 2011, Liberty Utilities (West)'s operating expenses excluding energy purchases totalled $16.0 million.

For the year ended December 31, 2011, Liberty Utilities (West)'s operating profit totalled $14.9 million.

	Three months ended December 31		Three months ended December 31	
	2011	2010	2011	2010
Customer Usage (GWhr)				
Residential			69.4	—
Commercial – Small			50.4	—
Commercial – Large			40.4	—
Total Customer Usage (GWhr)			**160.2**	
	U.S. $	U.S. $	**Can $**	Can $
Revenue				
Utility energy sales and distribution	**$ 20,805**	$ —	**$ 21,287**	$ —
Less:				
Cost of Sales – Energy*	**(13,176)**	—	**(13,486)**	
	$ 7,629	$ —	**$ 7,801**	$ —
Expenses				
Operating expenses	**(5,126)**	—	**(5,243)**	—
Division operating profit**	**$ 2,503**	$ —	**$ 2,558**	$ —

* Cost of Sales - Energy consists of energy purchases. Under GAAP, in APUC's consolidated Financial Statements, these amounts are included in operating expenses.

** Represents 100% of investment in the California Utility.

2011 Fourth Quarter Operating Results

For the quarter ended December 31, 2011, Liberty Utilities (West)'s customer usage totalled approximately 160,100 MWhr of energy.

For the quarter ended December 31, 2011, Liberty Utilities (West)'s revenue from utility energy sales totalled U.S. $20.8 million. The purchase of energy by the California Utility is a significant revenue driver and component of operating expenses but these costs are effectively passed through to its customers. As a result, the division compares 'net energy sales revenue' (energy sales revenue less energy purchases) as a more appropriate measure of the division's results. For the quarter ended December 31, 2011, Liberty Utilities (West)'s net utility energy sales revenue totalled U.S. $7.6 million.

For the quarter ended December 31, 2011, Liberty Utilities (West)'s energy purchases totalled U.S $13.2 million. During the quarter, the California Utility purchased approximately 160,100 MWhr of energy at rates averaging U.S. $82.3 per MWhr.

For the quarter ended December 31, 2011, Liberty Utilities (West)'s operating expenses, excluding energy purchases, totalled U.S. $5.1 million.

For the quarter ended December 31, 2011, Liberty Utilities (West)'s operating profit totalled U.S. $2.5 million. Liberty Utilities (West)'s operating profit did not meet expectations for the three months ended December 31, 2011 primarily due to higher than budgeted insurance, administration and distribution costs which include vegetation management and maintenance, partially offset by higher than budgeted net utility energy sales.

Measured in Canadian dollars, for the quarter ended December 31, 2011, Liberty Utilities (West)'s revenue from energy sales totalled $21.3 million. For the quarter ended December 31, 2011, Liberty Utilities (West)'s net energy sales revenue totalled $7.8 million.

Measured in Canadian dollars, for the quarter ended December 31, 2011, Liberty Utilities (West)'s energy purchases totalled $13.5 million.

Measured in Canadian dollars, for the quarter ended December 31, 2011, Liberty Utilities (West)'s operating expenses excluding energy purchases totalled $5.2 million.

For the quarter ended December 31, 2011, Liberty Utilities (West)'s operating profit totalled $2.6 million.

Outlook – Liberty Utilities (West)

Liberty Utilities (West) expects modest customer growth within its service territories in 2012. Liberty Utilities (West) anticipates that the California Utility should meet expectations for the first quarter of 2012.

On February 17, 2012, the California Utility filed a general rate case with the CPUC seeking, among other things, an increase of 10.0%, or $7.5 million in general rates, comprised of a $3.3 million increase in vegetation

management costs, $13.0 million increase in distribution rates offset by reductions in commodity costs of $8.8 million. The California Utility's proposed procedural schedule contemplates rates to be implemented on January 1, 2013.

On April 29, 2011, Liberty Utilities announced it had reached an agreement with Emera to acquire the interest in the California Utility held by Emera. Emera agreed to sell its 49.999% direct ownership in the California Utility, with closing of such transaction subject to regulatory approval. As consideration Emera will receive 8.211 million APUC shares in two tranches; approximately half of the shares will be issued following regulatory approval of the California Utility ownership transfer (expected in 2012) and the balance of the shares will be issued following completion of the California Utility's first rate case, expected to be completed in early 2013.

Liberty Utilities (East)

On December 9, 2010, Liberty Utilities entered into agreements to acquire all issued and outstanding shares of Granite State, a rate regulated New Hampshire electric utility, and EnergyNorth, a rate regulated New Hampshire natural gas utility for a total purchase price of U.S. $285 million, plus working capital and subject to certain other closing adjustments. The purchase prices for Granite State and EnergyNorth are based on anticipated regulatory assets at closing of approximately U.S. $72.0 million and U.S. $178.8 million, respectively. Upon completion of the transaction, the results of these utilities will be reported in a newly formed Liberty Utilities (East) division.

Granite State provides electric service to over 43,000 customers in 21 communities in New Hampshire. EnergyNorth provides natural gas services to over 83,000 customers in five counties and 30 communities in New Hampshire.

The closing of the transaction is subject to approval by the NHPUC. Liberty Utilities is currently proceeding through the regulatory approval process. A series of technical sessions with the NHPUC have been held to review the merits of the transaction, identify key transitional issues and resolve issues raised by commission staff, the consumer advocate and other interveners. Liberty Utilities and National Grid are now working with the NHPUC Staff and Consumer Advocate to prepare a settlement recommendation to present to the Commissioners of the NHPUC for consideration and ultimate approval. The current regulatory hearing schedule should allow for a public hearing in late Q1 2012, with a commission decision expected shortly thereafter. This would likely to result in closing occurring towards the end of Q2 2012.

In connection with these acquisitions, Emera has committed to a treasury subscription of subscription receipts convertible into 12.0 million APUC common shares upon closing of the transactions at a purchase price of $5.00 per share representing an approximate 5% premium to APUC's closing share price on December 8, 2010. The issuance of these subscription receipts is subject to regulatory approval.

Financing of these acquisitions is expected to occur simultaneously with the closing of the transactions. Liberty Utilities (East) is targeting a capital structure of not more than 50% debt to total capitalization consistent with investment grade utilities.

Liberty Utilities (Central)

On May 13, 2011, Liberty Utilities (Central) entered into an agreement with Atmos to acquire the gas utilities located in Missouri, Iowa, and Illinois. Total purchase price for the gas utilities is approximately U.S. $124 million, plus working capital and subject to certain other closing adjustments. Liberty Utilities expects to acquire assets for rate making purposes of approximately U.S. $112 million, plus working capital and subject to certain other closing adjustments, representing a purchase price multiple of 1.106x. The gas utilities currently provide natural gas local distribution service to approximately 84,000 customers (57,000 in Missouri, 23,000 in Illinois, and 4,000 in Iowa).

The closing of the transaction is subject to approval by the MPSC, the IUB, and the ICC. Liberty Utilities has received approval from the IUB and has entered a unanimous stipulation with the MPSC. Liberty Utilities is currently proceeding through the regulatory approval process with the ICC which requires the company, Atmos and the ICC staff to review the merits of the transaction. A hearing on a limited set of issues was held in Illinois in January 2012, and a proposed ICC decision is expected in Q2 2012. Management expects closing to occur towards the end of Q2 2012.

Upon completion of the transaction, the results of these utilities will be reported in the Liberty Utilities (Central) division. It is expected that management responsibility for the rate regulated water utility systems located in Missouri and currently reported in the results of Liberty Utilities (South) will be transferred to the newly formed Liberty Utilities (Central) following the acquisition of the Atmos assets.

Financing of this acquisition is expected to occur simultaneously with the closing of the transaction. Liberty Utilities (Central) is targeting a capital structure of not more than 50% debt to total capitalization consistent with investment grade utilities.

APUC: Corporate

	Three months ended December 31		Year ended December 31	
	2011 (millions)	2010 (millions)	**2011 (millions)**	**2010** (millions)
Corporate and other expenses:				
Administrative expenses and management costs	**4.8**	5.1	**17.5**	14.9
Write down of intangibles and property plant and equipment	**16.5**	2.5	**16.5**	2.5
Loss / (Gain) on foreign exchange	**0.4**	(0.1)	**(0.7)**	(0.5)
Interest expense	**7.6**	6.5	**30.4**	24.8
Interest, dividend and other Income	**(0.8)**	(1.0)	**(3.0)**	(3.6)
Loss / (Gain) on derivative financial instruments	**1.6**	(1.8)	**5.8**	1.1
Income tax recovery	**(6.6)**	(16.4)	**(23.0)**	(20.8)

2011 Annual Corporate and Other Expenses

During the year ended December 31, 2011, management and administrative expenses totalled $17.5 million, as compared to $14.9 million in the same period in 2010. The expense increase in the year ended December 31, 2011 results from additional personnel, increased wages, additional costs required to administer APUC's operations, stock option expense, franchise taxes, a provision related to water lease dues at the Cote St.-Catherine facility and other costs as compared to the same period in 2010.

In December 2011, APCo wrote down its investment in a small hydro facility and recognized an impairment charge on property, plant and equipment of $1.3 million representing the difference between the carrying value of the assets and their estimated fair value. The fair value of the facilities was estimated based on prior transactions involving sales of comparable facilities and management's best estimates. Subsequent to the year end, APCo entered into an agreement to sell certain small hydro facilities located in the U.S for gross proceeds of $0.2 million. The carrying value was written down to its fair value less cost to sell resulting in an impairment charge of $0.7 million, which was included in earnings for the period. The fair value of the equipment was based on the expected sales price. In addition, Liberty Utilities (South) wrote down certain facility's assets in the amount of $1.1 million as a result of regulatory decisions in 2011 that deemed certain capital expenditures not allowable for rate-base purposes.

Subsequent to the year end, the Region elected not to extend the existing EFW waste processing contract and is seeking competitive proposals from several waste management companies, including EFW. As a result, the remaining intangible assets associated with the existing waste management and energy contracts of the facility were written off in 2011 and APCo recognized an impairment charge on intangible assets of $13.4 million.

In the comparable period of 2010, APCo wrote down its investment in three small hydro facilities and recognized an impairment charge on property, plant and equipment of $1.8 million representing the difference between the carrying value of the assets and their fair value. The fair value of the facilities was estimated based on prior transactions involving sales of comparable facilities. The equipment was sold subsequent to December 31, 2010. The carrying value was written down to its fair value less cost to sell resulting in a loss of $0.7 million, which was included in earnings for the period. The fair value of the equipment was based on the sales price.

For the year ended December 31, 2011, interest expense totalled $30.4 million as compared to $24.8 million in the same period in 2010. Interest expense increased primarily as a result of higher levels of borrowings resulting from the acquisition of the California Utility and higher long term rates associated with Liberty Utilities (South)'s senior unsecured notes and APCo's senior unsecured debentures compared to the short term rates that are associated with a short term bank credit facility. In addition, there was higher average variable interest expense, partially offset by lower average borrowings and the conversion of the Series 1A Debentures in April 2011, as compared to the same period in 2010.

For the year ended December 31, 2011, interest, dividend and other income totalled $3.0 million, as compared to $3.6 million in the same period in 2010. Interest, dividend and other income primarily consists of dividends from APUC's share investment in the Kirkland and Cochrane facilities.

Loss on derivative financial instruments consists of realized and unrealized mark-to-market losses on interest rate swaps and forward energy purchase contracts during 2011. The unrealized portion of any mark-to-market gains or losses on derivative instruments does not impact APUC's current cash position.

An income tax recovery of $23.0 million was recorded in the year ended December 31, 2011, as compared to a recovery of $20.8 million in the same period in 2010. There are two primary reasons for the income tax recovery for the period ended December 31, 2011. First, in the third quarter of 2011, APUC completed a capital structure project to ensure its operating subsidiaries have a capital structure that is appropriate for its business sector and that uses the functional currency in which it operates. Therefore as part of this process, APUC converted Canadian dollar denominated intercompany notes with a U.S. subsidiary of APCo into U.S. dollar denominated preferred shares resulting in a realized foreign exchange loss for tax purposes and a release of the valuation allowance associated with the unrealized foreign exchange loss accumulated to that point, thereby creating a future tax asset of approximately $15.6 million that is now available as additional tax shelter in future years. Secondly, on October 27, 2009, Algonquin effectively converted from a publicly traded income trust to a publicly traded corporation. Included in future income tax recoveries for the year ended December 31, 2011 is $6.6 million related to the recognition of deferred credits from the utilization of future income tax assets which were set up based on the new corporate structure on October 27, 2009.

2011 Fourth Quarter Corporate and Other Expenses

During the quarter ended December 31, 2011, management and administrative expenses totalled $4.8 million, as compared to $5.1 million in the same period in 2010. The expense decrease in the three months ended December 31, 2011 primarily results from decreased capital taxes, partially offset by the reasons discussed in "*2011 Annual Corporate and Other Expenses*" above as compared to the same period in 2010.

In December 2011, APCo wrote down its investment in a small hydro facility. Subsequent to the year end, APCo entered into an agreement to sell certain small hydro facilities located in the U.S for gross proceeds of $0.2 million. Liberty Utilities (South) wrote down certain facility's assets in the amount of $1.1 million as a result of regulatory decisions in 2011 that deemed certain capital expenditures not allowable for rate-base purposes. Subsequent to the year end, EFW wrote off the remaining intangible assets associated with the existing waste management and energy contracts with the Region and recognized an impairment charge on intangible assets of $13.4 million. See the discussion in the annual corporate and other expenses section above for details related to this expense.

In the comparable period of 2010, APCo wrote down its investment in three small hydro facilities and the equipment at the Crossroads thermal facility in New Jersey. See the discussion in the annual corporate and other expenses section above for details related to this expense.

For the quarter ended December 31, 2011, interest expense totalled $7.6 million as compared to $6.5 million in the same period in 2010. Interest expense increased primarily as a result of higher levels of borrowings resulting from the acquisition of the California Utility and higher long term rates associated with Liberty Utilities (South)'s long term debt private placement compared to the short term rates that are associated with a short term bank credit facility. In addition, there was higher average variable interest expense, partially offset by lower average borrowings and the conversion of the Series 1A Debentures, as compared to the same period in 2010.

For the quarter ended December 31, 2011, interest, dividend and other income totalled $0.8 million, as compared to $1.0 million in the same period in 2010. Interest, dividend and other income primarily consists of dividends from APUC's share investment in the Kirkland and Cochrane facilities.

Loss (gain) on derivative financial instruments consists of realized and unrealized mark-to-market losses on interest rate swaps and forward energy purchase contracts during the quarter. The unrealized portion of any mark-to-market gains or losses on derivative instruments does not impact APUC's current cash position.

An income tax recovery of $6.6 million was recorded in the three months ended December 30, 2011, as compared to a recovery of $16.4 million in the same period a year ago. The income tax recovery for the three months ended December 31, 2011 results from those factors discussed in "*2011 Annual Corporate and Other Expenses"* above as compared to the same period in 2010. Included in future income tax recoveries for the three months ended December 31, 2011 is $1.2 million related to the recognition of deferred credits from the utilization of future income tax assets which were set up based on the new corporate structure on October 27, 2009.

Non-GAAP Performance Measures

Reconciliation of Adjusted EBITDA to net earnings

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

The following table is derived from and should be read in conjunction with the audited Consolidated Statement of Operations. This supplementary disclosure is intended to more fully explain disclosures related to Adjusted EBITDA and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to GAAP consolidated net earnings.

	Three months ended December 31		Year ended December 31	
	2011 (millions)	2010 (millions)	**2011 (millions)**	2010 (millions)
Net earnings attributable to Shareholders	**$ (8.5)**	$ 15.6	**$ 23.4**	$ 18.0
Add (deduct):				
Net earnings attributable to the non controlling interest	**0.5**	0.1	**3.9**	0.4
Income tax recovery	**(6.6)**	(16.4)	**(23.0)**	(20.8)
Interest expense	**7.6**	6.5	**30.4**	24.8
Acquisition Costs	**1.2**	2.3	**3.0**	3.0
Write down of intangibles, property, plant and equipment	**16.5**	2.5	**16.5**	2.5
Loss (gain) on derivative financial instruments	**1.6**	(1.8)	**5.8**	1.1
Loss (gain) on foreign exchange	**0.4**	(0.1)	**(0.7)**	(0.5)
Depreciation and amortization	**11.6**	12.1	**45.9**	46.6
Adjusted EBITDA	**$ 24.3**	$ 20.8	**$ 105.2**	$ 75.1

For the year ended December 31, 2011, Adjusted EBITDA totalled $105.2 million as compared to $75.1 million, a net increase of $30.1 million or 40% as compared to the same period in 2010. For the quarter ended December 31, 2011, Adjusted EBITDA totalled $24.3 million as compared to $20.8 million, a net increase of $3.5 million or 17% as compared to the same period in 2010.

The major factors impacting Adjusted EBITDA are set out below. A more detailed analysis of these factors is presented within the business unit analysis.

	Three months ended December 31, 2011 (millions)	Year ended December 31, 2011 (millions)
Comparative Prior Period Adjusted EBITDA	$ 20.8	$ 75.1
Significant Changes:		
Acquisition of the California Utility	2.5	15.1
EFW facility	(0.4)	5.2
Liberty Utilities (South) revenue increases primarily due to rate case approvals	0.7	7.2
Hydro Renewable due to improved hydrology (reduced hydrology in Q4)	(0.5)	6.1
St. Leon – primarily due to an increased wind resource	1.6	3.0
Administration and management costs	0.3	(2.6)
Lower results from the weaker U.S. dollar (stronger in Q4)	1.2	(1.7)
Tinker Hydro / AES primarily due to lower energy demand	(0.2)	(1.0)
Windsor Locks – change in operating model	(0.4)	(1.9)
Other	(1.3)	0.7
Current Period Adjusted EBITDA	**$ 24.3**	**$ 105.2**

Reconciliation of adjusted net earnings to net earnings

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

The following table is derived from and should be read in conjunction with the audited Consolidated Statement of Operations. This supplementary disclosure is intended to more fully explain disclosures related to adjusted net earnings and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to consolidated net earnings in accordance with GAAP.

The following table shows the reconciliation of net earnings to adjusted net earnings exclusive of these items:

	Three months ended December 31, 2011		Year ended December 31, 2011	
	2011 (millions)	2010 (millions)	2011 (millions)	2010 (millions)
Net earnings attributable to Shareholders	**$ (8.5)**	$ 15.6	**$ 23.4**	$ 18.0
Add:				
Loss (gain) on derivative financial instruments, net of tax	**1.0**	(1.2)	**3.9**	0.7
Loss (gain) on foreign exchange, net of tax	**0.4**	(0.1)	**(0.7)**	(0.5)
Write down of intangibles, property, plant and equipment	**13.1**	2.5	**13.2**	2.5
Acquisition costs, net of tax	**0.7**	1.4	**1.8**	1.8
Adjusted net earnings	**$ 6.7**	$ 18.2	**$ 41.6**	$ 22.5
Adjusted net earnings per share	**$ 0.05**	$ 0.19	**$ 0.36**	$ 0.24

For the year ended December 31, 2011, adjusted net earnings totalled $41.6 million as compared to adjusted net earnings of $22.5 million, an increase of $19.1 million as compared to the same period in 2010. The increase in adjusted net earnings in the year ended December 31, 2011 is primarily due to increased earnings from operations, partially offset by increased interest and administrative expenses and lower recoveries of deferred taxes as compared to the same period in 2010.

For the three months ended December 31, 2011, adjusted net earnings totalled $6.7 million as compared to $18.2 million, a decrease of $11.5 million as compared to the same period in 2010. The decrease in adjusted net earnings in the three months ended December 31, 2011 is primarily due to increased interest and administrative expenses and reduced recoveries of deferred taxes, partially offset by increased earnings from operations as compared to the same period in 2010.

Summary of Property, Plant and Equipment Expenditures

	Three months ended December 31		Year ended December 31	
	2011 (millions)	2010 (millions)	2011 (millions)	2010 (millions)
APCo				
Renewable Energy Division				
Capital expenditures	**$ 6.7**	$ 1.0	**$ 25.6**	$ 2.3
Acquisition of operating entities	**—**	—	**—**	40.3
Total	**$ 6.7**	$ 1.0	**$ 25.6**	$ 42.6
Thermal Energy Division				
Capital expenditures	**$ 4.5**	$ 0.5	$ 13.6	$ 11.6
Total	**$ 4.5**	$ 0.5	**$ 13.6**	$ 11.6
LIBERTY UTILITIES				
South				
Capital Investment in regulatory assets	**$ 1.5**	$ 4.5	**$ 10.9**	$ 6.6
Acquisition of operating entities	**0.4**	—	**1.3**	2.1
Total	**$ 1.9**	$ 4.5	**$ 12.2**	$ 8.7
West				
Capital Investment in regulatory assets	**$ 4.9**	$ —	**$ 10.3**	$ —
Acquisition of operating entities	**1.4**	3.1	**98.7**	3.1
Total	**$ 6.3**	$ 3.1	**$ 109.0**	$ 3.1
Consolidated				
Total APCo				
Capital expenditures	$ 11.2	$ 1.5	**$ 39.2**	$ 13.9
Acquisition of operating entities	—	—	**—**	40.3
Total Liberty Utilities				
Capital investment in regulatory assets	$ 6.4	4.5	**$ 21.2**	6.6
Acquisition of operating entities	1.8	3.1	**100.0**	5.2
Corporate	0.1	0.1	**0.4**	0.2
Total	**$ 19.5**	$ 9.2	**$ 160.8**	$ 66.2

APUC's consolidated capital expenditures in the year ended December 31, 2011 increased as compared to the same period in 2010 primarily due to the acquisition of the California Utility, the start of the construction of St. Leon II and the Windsor Locks repowering project.

Property, plant and equipment expenditures for 2012 are anticipated to be between $60 million and $70 million, including approximately $14.0 million related to ongoing requirements by Liberty Utilities (South), $11.0 million at Liberty Utilities (West) related to the California Utility, $15.5 million related to the APCo Thermal division, primarily related to the Windsor Locks repowering and major maintenance at the Sanger facility, and $18.5 million related to the APCo Renewable Energy division, primarily related to the St. Leon II expansion and a major project at the Tinker facility.

APUC anticipates that it can generate sufficient liquidity through internally generated operating cash flows, working capital and bank credit facilities to finance its property, plant and equipment expenditures and other commitments.

2011 Annual Property Plant and Equipment Expenditures

During the year ended December 31, 2011, APCo incurred net capital expenditures of $39.2 million, as compared to $13.9 million during the comparable period in 2010. APCo also invested $40.3 million to acquire operating assets/entities during the comparable period in 2010.

During the year ended December 31, 2011, APCo Renewable Energy division's capital expenditures were $25.6 million, as compared to $2.3 million in the comparable period in 2010. The St. Leon II development and the

turbine overhaul project at the Tinker facility were the major individual projects initiated in the current period. The APCo Renewable Energy division's acquisition of operating assets in 2010 relate to the Tinker Assets located in New Brunswick and Maine. The APCo Thermal Energy division's net capital expenditures were $13.6 million, as compared to $11.6 million in the comparable period in 2010. The major expenditures in the year primarily relates to the Windsor Locks repowering project and investments at the Sanger facility. In the comparable period, the capital expenditures primarily relate to the EFW facility where major capital maintenance was underway.

During the year ended December 31, 2011, Liberty Utilities invested $21.2 million in regulatory assets, as compared to $6.6 million during the comparable period in 2010. These investments comprise of $10.9 million at Liberty Utilities (South) and $10.3 million at Liberty Utilities (West). Liberty Utilities also invested $100.0 million to acquire operating assets/entities, primarily related to Liberty Utilities (West)'s investment of $98.7 million to acquire the California Utility in 2011.

2011 Fourth Quarter Property Plant and Equipment Expenditures

During the quarter ended December 31, 2011, APCo incurred net capital expenditures of $11.2 million, as compared to $1.5 million during the comparable period in 2010.

During the quarter ended December 31, 2011, APCo Renewable Energy division's capital expenditures were $6.7 million, as compared to $1.0 million in the comparable period in 2010. The major expenditures in the quarter primarily relates to the St. Leon II development and the turbine overhaul project at the Tinker facility. The APCo Thermal Energy division's net capital expenditures were $4.5 million, as compared to $0.5 million in the comparable period in 2010. The major expenditures in the quarter primarily relates to the Windsor Locks repowering project and investments at the Sanger facility.

During the quarter ended December 31, 2011, Liberty Utilities invested $6.4 million, as compared to $4.5 million during the comparable period in 2010. These investments comprise of $1.5 million at Liberty Utilities (South) and $4.9 million at Liberty Utilities (West). During the quarter, Liberty Utilities (West) recorded an adjustment to the purchase price of the California Utility which reduced the purchase price by $1.4 million.

Dam Safety Legislation

As a result of the dam safety legislation passed in Quebec (Bill C93), APCo's Renewable Energy division is required to undertake technical assessments of eleven of the twelve hydroelectric facility dams owned or leased within the Province of Quebec. All eleven dam safety evaluations have now been completed. Out of these, nine remedial plans have been submitted to the Quebec government and two are undergoing options analysis by APCo. The nine remedial plans have been accepted by the Quebec government and one is still being reviewed.

APCo has spent approximately $1.5 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:

	Total	2012	2013	2014	2015
Estimated future Bill C-93 Capital Expenditures	**16,900**	1,100	5,300	7,700	2,800

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 anticipates completing the on-site remediation work in 2012.
- 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 anticipates completing the engineering in 2012 and performing the remedial work in 2013 and 2014.

- The dam safety study for the St. Alban facility was completed in 2010 followed by a detailed condition assessment in 2011. APCO will review the results of the condition assessment and finalize the remediation plan for this dam in 2012. APCo anticipates engineering and regulatory review to be performed in 2012 and 2013, with remedial work 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.
- The dam remediation work related to Chute Ford will be completed in 2012 while the work related to the St. Raphael and Riviere-du-Loup facilities is anticipated to be completed in 2013. No dam remediation work is required at the Arthurville, Hydraska, and Ste-Brigitte facilities.
- The dam remediation work related to the Rawdon facility was completed in 2011.

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

LIQUIDITY AND CAPITAL RESERVES

The following table sets out the amounts drawn, letters of credit issued and outstanding amounts available to APUC and its subsidiaries as at December 31, 2011 under the Facility:

	2011 Q4 (millions)	2011 Q3 (millions)	2011 Q2 (millions)	2011 Q1 (millions)	2010 Q4 * (millions)
Committed and available Facility	$ 120.0	$ 120.0	$ 142.0	$ 142.0	$ 142.0
Funds Drawn on Facility	—	(12.0)	(70.0)	(65.0)	(64.5)
Letters of Credit issued	(39.6)	(40.1)	(32.5)	(32.9)	(33.1)
Remaining available Facility	**$ 80.4**	**$ 67.9**	**$ 39.5**	**$ 44.1**	**$ 44.4**
Cash on Hand	72.9	15.5	8.7	2.5	**4.7**
Total liquidity and capital reserves	**$ 153.3**	**$ 83.4**	**$ 48.2**	**$ 46.6**	**$ 49.1**

* Reflects availability as at December 31, 2010, under the terms of a three year Facility renewed subsequent to December 31, 2010, having a maturity of February 14, 2014.

During the first quarter, APCo concluded negotiations with its bank syndicate on the renewal of the Facility for a three year term with a maturity date of February 14, 2014. Algonquin also reduced the total of the Facility to $120 million following the completion of the Senior Unsecured Debenture offering of APCo in July 2011. As at December 31, 2011, no amounts had been drawn on the Facility as compared to $64.5 million as at December 31, 2010. In addition to amounts actually drawn, there were $39.6 million in letters of credit outstanding as at September 30, 2011. APCo had $80.4 million of committed and available bank facilities remaining and $72.9 million of cash resulting in $153.3 million of total liquidity and capital reserves.

On July 25, 2011, APCo completed the Senior Unsecured Debenture offering of $135 million, the net proceeds of which were used to repay the Airsource senior debt financing having a principal amount outstanding of $67.8 million with the balance being used to reduce amounts outstanding on the Facility.

On October 27, 2011, APUC completed an equity offering of $85.3 million, a portion of the net proceeds of which have been used to repay the outstanding balance on the Facility. 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 16,869,000 common shares under the Offering for the total gross proceeds of approximately $95.3 million.

On January 19, 2012, Liberty Utilities announced that it had entered into an agreement for a U.S. $80 million senior unsecured revolving credit facility (the “Liberty Facility”) with a three year term. Initially, U.S. $25 million will be available immediately to support the operations of Liberty Utilities and its current subsidiaries. The additional U.S. $55 million will be automatically available to Liberty Utilities to support operations and working capital requirements of all committed regulated utility acquisitions following the closing of the previously announced acquisition of Granite State and EnergyNorth. The Liberty Facility includes provisions which allow the available credit to be increased to accommodate future working capital needs or other requirements.

APUC intends to use its liquidity and capital reserves to fund announced capital expansion projects in APCo and to partially fund announced share acquisitions in Liberty Utilities.

CONTRACTUAL OBLIGATIONS

Information concerning contractual obligations as of December 31, 2011 is shown below:

	Total (millions)	Due less than 1 year (millions)	Due 1 to 3 years (millions)	Due 4 to 5 years (millions)	Due after 5 years (millions)
Long-term debt obligations[1]	$ 332.7	$ 1.6	$ 3.7	$ 16.5	$ 310.9
Convertible debentures[2]	$ 122.3	—	—	59.7	62.6
Interest on long-term debt obligations	$ 227.9	25.6	40.2	37.3	124.8
Long term service agreements	$ 94.4	4.6	8.2	8.6	73.0
Purchased power	$ 227.5	45.1	91.5	90.9	—
Accounts payable/purchase obligations	$ 57.3	57.3	—	—	—
Capital Projects	$ 7.9	7.9	—	—	—
Energy forward purchase contract	$ 1.2	0.8	0.4	—	—
Interest rate swap	$ 6.9	2.1	3.7	1.1	—
Lease obligations	$ 2.7	1.2	1.2	0.3	—
Other obligations	$ 9.8	1.1	0.5	0.5	7.7
Total obligations	$1,090.6	$ 147.3	$ 149.4	$ 214.9	$ 579.0

[1] Long term obligations include regular payments related to long term debt and other obligations.
[2] Convertible debentures include the Series 2A Debentures which were redeemed for equity effective February 24, 2012.

SHAREHOLDER'S EQUITY AND CONVERTIBLE DEBENTURES

The shares of APUC are publicly traded on the Toronto Stock Exchange ("TSX"). As at December 31, 2011, APUC had 136,122,780 issued and outstanding shares. Following the Series 2A Redemption, APUC had 146,741,635 shares outstanding.

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

APUC is also authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board. As at December 31, 2011, APUC does not have any issued and outstanding preferred shares.

As at December 31, 2011, APUC had issued to Emera a treasury subscription of subscription receipts convertible into 12.0 million APUC common shares upon closing of the Granite State and EnergyNorth transactions at a purchase price of $5.00. Delivery of the shares under the subscription receipts is conditional on and is planned to occur simultaneously with the closing of the acquisition of Granite State and EnergyNorth. The proceeds of the subscription receipts are to be utilized to fund a portion of the cost to acquire Granite State and EnergyNorth.

On April 29, 2011, APUC agreed to issue to Emera 8.2 million shares with regards to the acquisition by Liberty Utilities of Emera's 49.999% direct ownership in the California Utility. The approval on the ownership transfer is expected in early 2012. The payment of shares is to be made in two tranches with approximately half of the shares being issued following regulatory approval of the ownership transfer and the balance of the shares being issued following completion of the California Utility's first rate case which is expected to be completed in 2012.

On April 30, 2011, APUC committed to issuance to Emera of a treasury subscription of subscription receipts convertible into approximately 6.9 million APUC common shares upon closing of the transaction related to the acquisition of an interest in a portfolio of 370MW wind projects. This treasury subscription was terminated when APCo announced on January 27, 2012 that it no longer intended to proceed with the First Wind acquisition.

On April 7th, 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 Redemption Date, a principal amount of $60,339 of Series 1A Debentures were converted into 14,788,975 shares of APUC. On the Redemption Date, APUC issued and delivered 430,666 APUC shares to the remaining holders of the Series 1A Debentures, representing the number of freely tradeable APUC shares obtained by dividing the aggregate principal amount of Debentures, by 95% of the current market price of APUC shares on the Redemption Date. On December 31, 2011, as a result of the Redemption there were no Series 1A Debentures outstanding.

Subsequent to December 31, 2011, on January 20, 2012, APUC provided the holders of its Series 2A 6.35% convertible unsecured subordinated debentures due November 30, 2016 ("Series 2A Debentures") notice of its intention to redeem for equity, effective February 24, 2012 ("Series 2A Redemption Date"), all of the issued and outstanding Debentures. Prior to the Series 2A Redemption Date, a principal amount of $2,916 of Series 2A Debentures were converted into 485,998 shares of APUC.

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 tradeable APUC shares obtained by dividing the aggregate principal amount of Debentures of $57,041, by 95% of the current market price of APUC shares on the Series 2A Redemption Date. As a result, there are no Series 2A Debentures outstanding subsequent to the Series 2A Redemption Date.

On December 2, 2009, APUC issued 63,250 convertible unsecured debentures at a price of $1,000 for each debenture maturing on June 30, 2017 ("Series 3 Debentures"). The Series 3 Debentures bear interest at 7.0% per annum, payable semi-annually in arrears on June 30 and December 30 each year, and are convertible into common shares of APUC at the option of the holder at a conversion price of $4.20 per common share, being a ratio of approximately 238.1 common shares for each $1,000 principal. The Series 3 Debentures may not be redeemed by APUC prior to December 31, 2012. During the period of January 1, 2013 until December 31, 2014, the Series 3 Debentures may be redeemed by APUC provided that the weighted-average trading price of the underlying share price on the TSX for the 20 consecutive trading days is equal to or exceeds a price of $5.25 (125% of the conversion price of $4.20). During the period of January 1, 2015 until the Series 3 Debentures' maturity, APUC can redeem the Series 3 Debentures for 100% of the face value of the Series 3 Debentures with cash, or for 105% of the face value of the Series 3 Debentures with additional shares.

On December 31, 2011, there were 62,571 Series 3 Debentures outstanding with a face value of $62,571.

During the three months ended December 31, 2011, a principal amount of $129 Series 3 Debentures were converted into 30,710 shares APUC. During the year ended December 31, 2011, a principal amount of $334 Series 3 Debentures were converted into 79,517 shares APUC. Subsequent to the end of the quarter, $66 Series 3 Debentures were converted to 15,711 shares.

SHARE BASED COMPENSATION PLANS

For the year ended December 31, 2011, APUC recorded $0.7 million (2010 - $0.1 million) in total share-based compensation expense. No tax deduction was realized in the current year. The compensation expense is recorded as part of the operating expenses in the Consolidated Statement of Operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at December 31, 2011, total unrecognized compensation costs related to non-vested options and share unit awards were $1.2 million and $0.1 million respectively, which are expected to be recognized over a period of 1.76 years and 2 years respectively.

STOCK OPTION PLAN

On June 23, 2010, APUC's shareholders approved a stock option plan (the "Plan") that permits the grant of share options to key officers, directors, employees and selected service providers. On June 21, 2011, APUC's shareholders approved amendments to the Plan to limit non-employee director participation in the Plan and to require shareholder approval to make further amendments to the plan with respect to a number of items as more fully described in the management information circular for the 2011 annual and special meeting of shareholders.

During the year ended December 31, 2010, 1,160,204 options were granted to senior executives of APUC which allow for the purchase of common shares at a price of $4.05. One-third of the options vest on each of January 1, 2011, 2012 and 2013. During the year ended December 31, 2011, the Board approved the following grant of options:

- On March 22, 2011, 892,107 options were granted to senior executives of APUC which allow for the purchase of common shares at a price of $5.23;
- On June 21, 2011, 171,642 options were granted to a senior executive of APCo which allow for the purchase of common shares at a price of $5.64;

- On July 28, 2011, 90,909 options were granted to a senior executive of APUC which allow for the purchase of common shares at a price of $5.74; and
- On September 13, 2011, 172,242 options were granted to a senior executive of Liberty Utilities which allow for the purchase of common shares at a price of $5.68.

Subsequent to year end on March 14, 2012, 1,194,606 options were granted which allow for the purchase of common shares at a price of $6.22.

All options are issued at the market price of the underlying common share at the date of grant. In each case, one-third of the options vest on each of January 1, 2012, 2013 and 2014. Options may be exercised up to eight years following the date of grant.

During the year ended December 31, 2011, no options were exercised. As at December 31, 2011, APUC had 2,487,104 options issued and outstanding. APUC determines the fair value of options granted using the Black-Scholes option-pricing model. The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date.

As at December 31, 2011, 386,735 options with an intrinsic value of $917 are exercisable. No share options were exercised in 2011 or 2010. The intrinsic value of the 2,487,104 options as at December 31, 2011 was $4,134.

PERFORMANCE SHARE UNITS

In October 2011, APUC issued 28,370 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 period and are converted to PSUs based on the market value of the shares on that date. None of these PSUs have voting rights. Any PSUs not vested at the end of a performance period will expire. The PSUs provide for settlement in cash or shares at the election of APUC. As APUC does not expect to settle these instruments in cash, these PSUs will be accounted for as equity awards. Compensation expense associated with PSUs is recognized rateably over the performance period based on APUC's estimated achievement of the established metrics. Compensation expense for awards with performance conditions will only be recognized for those awards for which it is probable that the performance conditions will be achieved and which are expected to vest. The compensation expense will be estimated based upon an assessment of the probability that the performance metrics will be achieved and anticipated vesting percentage.

DIRECTORS DEFERRED SHARE UNITS

In June 2011, the Shareholders approved a Deferred Share Unit Plan. Under the plan, non-employee directors of APUC may elect annually to receive all or any portion of their compensation in deferred share units ("DSUs") in lieu of cash compensation. 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 expects to settle these instruments in cash, these DSUs will be accounted for as liability awards. The DSU liabilities will be marked-to-market at the end of each period based on the common share price at the end of the period.

As at December 31, 2011, no DSUs had been issued.

EMPLOYEE SHARE PURCHASE PLAN

In September 2011, APUC approved an employee share purchase plan ("ESPP"). Eligible employees may 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 match 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, 2011, a total of 7,176 shares had been issued under the ESPP. For the three and twelve month period ended December 31, 2011, APUC recorded $9 in compensation expense.

DIVIDEND REINVESTMENT PLAN

Effective October 1, 2011, APUC introduced a shareholder dividend reinvestment plan (the "Reinvestment Plan") which will be offered to registered holders of shares ("Shareholders") of APUC.

The purpose of the Reinvestment Plan is to enable Shareholders to invest all cash dividends on Shares in additional shares of APUC ("Plan Shares"). All such Plan Shares will be, at APUC's election, either (i) Shares purchased on the open market through the facilities of the TSX ("Market Purchase") or (ii) newly issued 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 Shares of APUC 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 December 31, 2011, 23.6 million common shares had been registered with the Reinvestment Plan.

MANAGEMENT OF CAPITAL STRUCTURE

APUC views its capital structure in terms of its debt levels, both at a project and an overall company level, in conjunction with its equity balances.

APUC's objectives when managing capital are:

- To maintain its capital structure consistent with investment grade credit metrics appropriate to the sectors in which APUC operates;
- To maintain appropriate debt and equity levels in conjunction with standard industry practices and to limit financial constraints on the use of capital;
- To ensure capital is available to finance capital expenditures sufficient to maintain existing assets;
- To ensure generation of cash is sufficient to fund sustainable dividends to shareholders as well as meet current tax and internal capital requirements;
- To maintain sufficient cash reserves on hand to ensure sustainable dividends made to shareholders; and
- To have proper credit facilities available for ongoing investment in growth and investment in development opportunities.

APUC monitors its cash position on a regular basis to ensure funds are available to meet current normal as well as capital and other expenditures. In addition, APUC continuously reviews its capital structure to ensure its individual business units are using a capital structure which is appropriate for their respective industries.

RELATED PARTY TRANSACTIONS

- Certain executives of APUC are shareholders of Algonquin Power Management Inc. (APMI), the former manager of APCo. A member of the Board of Directors of APUC is an executive at Emera.
- APUC has leased its head office facilities since 2001 from an entity owned by the shareholders of APMI on a triple net basis. Base lease costs for the three and twelve months ended December 31, 2011 were $82 and $327, respectively (2010 - $82 and $327). Based on a review of the real estate leasing market at the time, APUC believes the lease was entered into on terms equivalent to fair market value for prime office space of similar size and quality.
- APUC utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI, Algonquin Airlink Inc. In 2004, APUC entered into an agreement and remitted $1,300 to the affiliate as an advance against expense reimbursements (including engine utilization reserves) for APUC's business use of the aircraft. Under the terms of this arrangement, APUC has priority access to make use of the aircraft for a specified number of hours at a cost equal solely to the third party direct operating costs incurred when

flying the aircraft. During the three and twelve months ended December 31, 2011, APUC incurred costs in connection with the use of the aircraft of $103 and $453, respectively (2010 - $60 and $430) and amortization expense related to the advance against expense reimbursements of $69 and $274, respectively (2010 - $13 and $112). At December 31, 2011, the remaining amount of the advance was $279 (2010 - $554) and is recorded in other assets.

- Affiliates of APMI hold 60% of the outstanding Class B limited partnership units issued by the St. Leon Wind Energy LP ("St. Leon LP"), a subsidiary of APUC and the legal owner of the St. Leon facility. The holders of the Class B Units are entitled to 2.5% of the income allocations and cash distributions from St. Leon LP for a five year period commencing two years after the commercial operation date of the facility of June 17, 2006, increasing by 2.5% every 5 years to a maximum of 10%. In any particular period, cash distributions to the holders of the Class B Units are only to be made after distributions have been made to the other partners, in an aggregate amount, equal to the debt service on the outstanding debt in respect of such period. The related holders of the Class B units received cash distributions of $106 and $314 for the three and twelve months ended December 31, 2011 (2010 - $77 and $266).
- APMI is one of the two original developers of Red Lily I and both developers are entitled to a royalty fee based on a percentage of operating revenue and a development fee from the equity owner of Red Lily I. The royalty fee is initially equal to 0.75% of gross energy revenue, increasing every five years up to 2% after twenty-five years. During the year, APUC acquired APMI's interest in this royalty for an amount of $600. This amount has been recorded as a purchase of intangible assets and the amount owing to APMI is included in accrued liabilities at December 31, 2011.
- Staff managed by APUC have historically operated an additional three hydroelectric generating facilities not owned by APUC where Senior Executives hold an equity interest. Effective January 1, 2011, management of these facilities is now being undertaken by Algonquin Power Systems Inc. ("APS") an entity where Senior Executives hold equity interests. APUC and APS had agreed to provide some transition services to each other until December 31, 2011. This agreement has been extended for an additional year in relation to one of the hydroelectric generating facilities. Costs for providing such transition services are intended to be on a cost recovery basis with no mark-up.
- As at December 31, 2011, included in amounts due from related parties is $663 (2010 - $718) owed to APUC from APMI and included in amounts due to related parties is $1,795 (2010 - $901) owed to APMI. These amounts arise from the transactions described above.
- A contract with a subsidiary of Emera to purchase energy on ISO NE and provide scheduling services on ISO NE was included as part of the acquisition of AES associated with the Tinker Acquisition. The contract expired March 31, 2010 and was not renewed. As a result of this contract, during 2010 a subsidiary of Emera provided services to and purchased energy on ISO NE on behalf of AES. In this capacity, APUC paid a subsidiary of Emera an amount of $0 (2010 - $0 and $1,368) during the three and twelve months ended December 31, 2011 which was included as an operating expense on the consolidated statement of operations.
- In 2010, APUC entered into a one year contract with a subsidiary of Emera to provide lead market participant services for fuel capacity and forward reserve markets in ISO NE for the Windsor Locks facility. During the three and twelve months ended December 31, 2011 APUC paid U.S. $73 and $260 (2010 - $64 and $196) in relation to this contract. In the same period, APUC provided a corporate guarantee to a subsidiary of Emera in an amount of U.S. $1,000 in conjunction with this contract.
- On December 21, 2010, a subsidiary of Emera acquired Maine & Maritimes Corporation, the parent company of Maine Public Service Company ("MPS"). During the three and twelve months ended December 31, 2011, AES sold electricity to MPS amounting to $1,263 and $6,564 (2010 - $0). In the same period, APUC provided a corporate guarantee to MPS in an amount of U.S. $3,000 and a letter of credit in an amount of U.S $100, primarily in conjunction with a three year contract to provide standard offer service to commercial and industrial customers in Northern Maine.
- In 2008, APUC entered into an agreement with Highground Capital Corporation ("Highground") and CJIG Management Inc. ("CJIG) whereby, CJIG acquired all of the issued and outstanding common shares of Highground and APUC issued equity to the Highground shareholders and CJIG, in exchange for $26.2 million cash and future consideration based on 50% of liquidation proceeds from sale of Highground's remaining assets by CJIG. During 2011, APUC received additional consideration of $1,073 (2010 - $170) from CJIG as APUC's share of additional proceeds. This has been recorded as an increase to share capital. As at December 31, 2011, further consideration from this transaction, if any, is not expected to be significant.

- As of December 31, 2011, included in amounts due from related parties is $1,612 (2010 - $0) owed from Emera related to the unpaid contribution of their share of the costs related to the California Utility.
- 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 after tax equity cash flows commencing in 2014.
- APUC believes that the transactions noted above were in accordance with normal commercial terms. The above related party transactions have been recorded at the exchange amounts agreed to by the parties to the transactions.

Business Associations with APMI and Senior Executives.

There have been a number of business relationships between Ian Robertson and Chris Jarratt ("Senior Executives"), APMI 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 conducted 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, 2011 are listed below. Subsequent to December 31, 2011, APUC and the Parties reached an agreement to resolve a number of the business associations and relationships (the "Agreement"). A more detailed description of the Agreement has been set out below in *Settlement of Other Business Associations.*

i) Rattlebrook hydroelectric generating facility

Rattlebrook is a 4 MW hydroelectric generating station owned 45% by APUC and 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.

ii) St. Leon wind power generating facility

St. Leon is a 104 MW wind power generating facility which has issued Class B units to external parties and Senior Executives. APUC and the Class B unit holders have simplified the relationship by amalgamating the previous partnership agreement and two amending agreements into an amended and restated agreement. In addition, APUC and the Class B holders have executed an agreement which outlines the relationship of the parties in relation to the St. Leon II expansion of the St Leon facility ("Expansion Agreement"). The terms of the Expansion Agreement allow APUC to expand the St Leon project on a "no-net-harm-basis" to the Class B holders and provide APUC with the full economic benefit of such expansion.

iii) 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 $100 in relation to the development of this project. In 2008, APUC accrued $100 as an estimate of the final fee owed to APMI. This relationship and corresponding liability was addressed pursuant to the Agreement.

iv) 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.

v) Chartered aircraft

APUC utilizes chartered aircraft owned by an affiliate of APMI. APUC entered into an agreement and remitted $1.3 million to the affiliate as an advance against expense reimbursements. At December 31, 2011, $279 of the advance remained. The Board has undertaken an independent review of the relationship and believes that continuing the original arrangement is beneficial to the company. The current arrangement is expected to end in approximately 2016 when the advance will be fully utilized.

vi) Office lease

APUC has leased its head office facilities on a triple net basis from an entity partially owned by Senior Executives. The original lease was due to expire in December 31, 2012. Effective April 1, 2011, a subsidiary of APUC leased its head office facilities from a third party in a new stand alone building immediately adjacent to APUC's head office for a term of 5 years ending December 31, 2015 with an additional 5 year renewal option. APUC has amended its lease at its existing premises to be co-terminus with its subsidiary's new lease. The majority of terms in the amended lease are identical. Based on a review of the real estate leasing market in the fall of 2010, APUC believes the amended lease is on terms equivalent to fair market value for prime office space of similar size and quality.

vii) Operations services

Staff managed by APUC have historically operated an additional three hydroelectric generating facilities where Senior Executives hold an interest. Effective January 1, 2011, management of these facilities is now being undertaken by an affiliate of APMI. APUC and the APMI affiliate had agreed to provide some transition services to each other until December 31, 2011. Costs for providing such transition services are intended to be on a cost recovery basis with no mark-up for profit. APUC agreed to provide supervisory management on a cost recovery basis for one of the facilities until December 31, 2012 to provide sufficient time for APMI to make alternative arrangements to manage the facility.

viii) 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. In 2008, APUC accrued U.S. $0.6 million as an estimate of the final fee owed to APMI. This liability was settled pursuant to the Agreement.

ix) 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 liability was settled pursuant to the Agreement.

x) 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. APUC has acquired APMI's interest in these royalties for an amount of $0.6 million. APMI is also entitled to a development fee of up to $0.4 million following commercial operation of the project and has agreed to permit the Board to determine whether it will retain this fee following commercial operation of the facility. This liability was settled pursuant to the Agreement.

xi) 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. The Second Circuit Court of Appeals dismissed all the claims against APCo in the civil proceedings and remanded one issue to the District Court. The bankruptcy proceedings are continuing.

Settlement of Other Business Associations.

Subsequent to December 31, 2011, APUC and the Parties reached an Agreement to resolve a number of the historic joint business associations between APUC and the Parties. The transaction is subject to finalization of definitive agreements which are expected to be completed in the second quarter of 2012.

Under this term sheet, it is proposed that 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 Sanger repowering project, the offer to acquire Clean Power 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.

TREASURY RISK MANAGEMENT

APUC attempts to proactively manage the risk exposures of its subsidiaries in a prudent manner. APUC ensures that both APCo and Liberty Utilities maintain insurance on all of their facilities. This includes property and casualty, boiler and machinery, and liability insurance. It has also initiated a number of programs and policies including currency and interest rate hedging policies to manage its risk exposures.

There are a number of monetary and financial risk factors relating to the business of APUC and its subsidiaries. Some of these risks include the U.S. versus Canadian dollar exchange rates, energy market prices, any 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 may encounter. A further assessment of APUC and its subsidiaries' business risks is also set out in the most recent AIF.

Foreign currency risk

Currency fluctuations may affect the cash flows APUC would realize from its consolidated operations, as certain APUC subsidiary businesses sell electricity or provide utility services in the United States and receive proceeds from such sales in U.S. dollars. Such APUC businesses also incur costs in U.S. dollars. At the current exchange rate, approximately 55% of EBITDA in 2012 and 65% 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 $5.4 million ($0.05 per share) on an annual basis.

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

Market price risk

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.

Credit/Counterparty risk

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

APUC does not believe this risk to be significant as approximately 82% of APCo Renewable Energy division's revenue, approximately 48% of APCo Thermal Energy division's revenue, and over 68% of APCo's total revenue is earned from large utility customers having a credit rating of BBB or better, and revenue is generally invoiced and collected within 45 days.

The following chart sets out APCo's significant counterparties, their credit ratings and percentage of total revenue associated with the counterparty:

Counterparty	Credit Rating *	Approximate Annual Revenues	Percent of Divisional Revenue
Renewable Energy Division			
Hydro – Quebec	A+	23,200	26%
Manitoba Hydro	AA	22,400	25%
Ontario Electricity Financial Corporation	A+	11,000	12%
MPS**	BBB+	6,600	7%
TransAlta Corp – Dickson Dam	BBB	4,000	5%
Public Service Company of New Hampshire	BBB	3,200	4%
National Grid	A-	3,000	3%
Total		**$ 73,400**	**82%**
Thermal Energy Division			
Regional Municipality of Peel	AAA	16,400	25%
Pacific Gas and Electric Company	BBB+	14,600	23%
Total		**$ 31,000**	**48%**

* Ratings by Dunn & Bradstreet or Standard & Poor's as of February 2012.
** MPS is a subsidiary of Emera.

The remaining revenue is primarily earned by Liberty Utilities. In this regard, the credit risk related to Liberty Utilities (South) accounts receivable balances of U.S. $5.1 million is spread over approximately 76,000 customers, resulting in an average outstanding balance of approximately $70.00 per customer. Liberty Utilities (West) has accounts receivable balances of U.S. $14.2 million with over 50% of revenue generated by residential customers.

Interest rate risk

APCo has a number of project specific and other debt facilities that are subject to a variable interest rate. These facilities and the sensitivity to changes in the variable interest rates charged are discussed below:

- The Facility has no amounts outstanding as at December 31, 2011. As a result, a 100 basis point change in the variable rate charged would not impact interest expense.
- APCo's project debt at the St. Leon facility had a balance of $67.8 million as at June 30, 2011. The outstanding balance was repaid during the quarter ended September 30, 2011 using proceeds from the Senior Unsecured Debenture offering. Accordingly there is no further interest rate risk associated with this debt facility.

- APCo's project debt at its Sanger cogeneration facility has a balance of U.S. $19.2 million as at December 31, 2011. 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.
- APCo's project debt at Long Sault, Chute Ford and its $135 million senior unsecured debentures bear fixed rates of interest and are not subject to interest rate risk.

Liberty Utilities (South)'s project debt at the Litchfield and Bella Vista Facilities are subject to a fixed rate of interest and thus are not subject to interest rate risk. Liberty Utilities (South)'s U.S. $50 million senior unsecured notes have a term of 10 years, a fixed rate of interest at 5.6% and are not subject to interest rate risk.

Liberty Utilities (West)'s U.S. $70 million senior unsecured private debt placement at the California Utility is 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. As such these notes are not subject to interest rate risk.

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. APUC's approach to managing liquidity risk is to ensure, to the extent possible, that it will always have sufficient liquidity to meet liabilities when due.

APUC currently pays a dividend of $0.28 per 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, ensure APUC's long-term success. Based on the level of dividends paid during the year ended December 31, 2011, cash provided by operating activities exceeded dividends declared by 2.1 times.

As at December 31, 2011, APUC had cash on hand of $72.9 million and $80.4 million available to be drawn on the Facility. APUC reduced its level of short-term borrowings through the renewal of the Facility on February 14, 2011 for a three year term and through a U.S. $50 million private placement debt financing at Liberty Utility (South) on December 22, 2010. On July 25, 2011, APCo completed a private placement offering of the Senior Unsecured Debentures with a principal amount of $135 million. Net proceeds from the debentures were used to repay the project debt on APCo's AirSource senior debt financing which would have matured on October 2011, and to reduce amounts outstanding under APCo's senior credit facility. See the *Liquidity and Capital Reserves* section for a more detailed discussion and chart of the funds available to APUC and its subsidiaries under the Facility.

The long term portion of Facility and project specific debt total approximately $331.1 million with maturities set out in the Contractual Obligation table. In the event that APUC was required to replace the Facility and project debt with borrowings having less favourable terms or higher interest rates, the level of cash generated for dividends and reinvestment may be negatively impacted. APUC attempts to manage the risk associated with floating rate interest loans through the use of interest rate swaps.

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

Commodity price risk

APCo's exposure to commodity prices is primarily limited to exposure to natural gas price risk. Liberty Water is not subject to any material commodity price risk. In this regard, a discussion of this risk is set out as follows:

- 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 $0.1 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 an increase in net revenue by approximately $1.4 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 130,000 MW-hrs in fiscal 2012. While the Tinker facility is expected to provide the majority 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 $1.3 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 70,000 MW-hrs of net energy over the next 12 months at an average rate of approximately U.S. $50 per MW-hr. The mark-to-market value of these forward energy purchase contracts at December 31, 2011 was a net liability of U.S. $1.2 million.

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 basin and surrounding areas at rates approved by the CPUC. The utility purchases the energy requirements for its customers from NV Energy at rates reflecting NV Energy's system average costs. In the event that these rates change, each $10.00 change per MWhr would result in a change in expense of approximately U.S. $6.5 million on an annualized basis.

The rate structure in California allows for a pass-through of energy costs to rate payers on a dollar for dollar basis, through the energy cost adjustment clause ("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.

OPERATIONAL RISK MANAGEMENT

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

There are a number of risk factors relating to the business of APUC and its subsidiaries. Some of these risks include the dependence upon APUC businesses, regulatory climate and permits, tax related matters, gross capital requirements, labour relations, reliance on key customers and environmental health and safety considerations. The risks discussed below are not intended as a complete list of all exposures that APUC and its subsidiaries may encounter. A more detailed assessment of APUC's business risks is also set out in the most recent AIF.

Mechanical and Operational Risks

APUC is entirely dependant upon the operations and assets of APUC's businesses. This profitability could be impacted by equipment failure, the failure of a major customer to fulfill its contractual obligations under its PPA, reductions in average energy prices, a strike or lock-out at a facility and expenses related to claims or clean-up to adhere to environmental and safety standards. The water distribution networks of Liberty Utilities operate under pressurized conditions within pressure ranges approved by regulators. Should a water distribution network become compromised or damaged, the resulting release of pressure could result in serious injury or

death to individuals or damage to other property. The electricity distribution systems owned by Liberty Utilities are subject to storm events, usually winter storm events, whereby power lines can be brought down with the attendant risk to individuals and property. In addition, in forested areas, power lines brought down by wind can ignite forest fires which also bring attendant risk to individuals and property.

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. In addition, APCo's existing long term PPAs minimize the risk of reductions in average energy pricing.

Regulatory Risk

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

Liberty Utilities' facilities are subject to rate setting by State regulatory agencies. The time between the incurrence of costs and the granting of the rates to recover those costs by State regulatory agencies is known as regulatory lag. As a result of regulatory lag, inflationary effects may impact the ability to recover expenses, and profitability could be impacted. Federal, State and local environmental laws and regulations impose substantial compliance requirements on electricity and natural gas distribution utilities. Operating costs could be significantly affected in order to comply with new or stricter regulatory requirements.

Electricity and natural gas distribution utilities could be subject to condemnation or other methods of taking by government entities under certain conditions. While any taking by government entities would require compensation be paid to Liberty Utilities, and while Liberty Utilities believes it would receive fair market value for any assets that are taken, there is no assurance that the value received for assets taken will be in excess of book value.

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

Asset Retirement Obligations

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

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

Based on its assessments, APUC's businesses do not have any significant retirement obligation liabilities and APUC has not recorded any liability in its consolidated financial statements as at December 31, 2011.

Environmental Risks

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

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

In order to monitor and mitigate these risks and to remain within the regulatory requirements appropriate for these assets, Liberty Utilities investigates promptly all reported accidental releases to take all required remedial actions and manages hazardous waste and universal waste streams in accordance with the applicable Federal and State Legislation.

APUC's policy is to record estimates of environmental liabilities when they are known or considered probable and the related liability is estimable. There are no known material environmental liabilities as at December 31, 2011.

Cycles and Seasonality

The hydroelectric operations of APCo are impacted by seasonal fluctuations. These assets are primarily "run-of-river" and as such fluctuate with the natural water flows. During the winter and summer periods, flows are generally lower while during the spring and fall periods flows are generally higher. The ability of these assets to generate income may be impacted by changes in water availability or other material hydrologic events within a watercourse. It is, however, anticipated that due to the geographic diversity of the facilities, variability of total revenues will be minimized.

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

At Liberty Utilities (South), 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.

For Liberty Utilities (West), demand for energy is primarily affected by weather conditions and conservation initiatives. Above normal snowfall in the Lake Tahoe area brings more tourists with an increased demand for electricity by small commercial customers. Liberty Utilities (West) provides information and programs to its customers to encourage the conservation of energy. In turn, demand may be reduced which could have short term adverse impacts to revenues.

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. For additional comments on this matter, see *"Business Associations with APMI and Senior Executives - Trafalgar"*.

On December 19, 1996, the Attorney General of Québec (“Québec AG”) filed a suit in Québec Superior Court against a subsidiary of APUC claiming for amounts that the APUC subsidiary has been paying to The St. Lawrence Seaway Management Corporation (“Seaway Management”) under its water lease with Seaway Management. The water lease contains a “hold harmless” clause which mitigates this claim. As such, the APUC subsidiary brought the Attorney General of Canada and Seaway Management (the “Federal Authorities”) into the proceedings in an action in warranty. On March 27, 2009, the Superior Court dismissed the claim of the Québec AG and suspended the action in warranty following final judgment in this case.

The Québec AG subsequently appealed this decision and on October 21, 2011 the Québec Court of Appeal allowed the appeal and condemned the APUC subsidiary to pay approximately $5.4 million which includes the amount claimed with interest.

The APUC subsidiary believes it is held harmless in its water lease from this decision. The Federal Authorities have decided not to appeal this decision to the Supreme Court of Canada. APUC and Seaway Management are now required to go back to the Superior Court of Quebec which will determine the amount of money reimbursable by Seaway Management to APUC pursuant to the terms of the Water Lease. As a result, the probability of loss, if any, and its quantification cannot be estimated at this time but could range from $nil to $4.8 million. Accordingly, no accruals for amounts owed or recoverable in respect of the water lease dues already paid to Seaway Management have been recorded in the financial statements. Conversely, APCo accrued $1.0 million of water lease owed to Québec AG for 2008 to 2011, which years are subsequent to those covered by the Court Decision and might not be subject to the legal right of offset. Probable amounts recoverable from the Federal Authorities of $0.3 million were also recorded in 2011.

Obligations to serve

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

Disclosure Controls

At the end of the fiscal year ended December 31, 2011, APUC carried out an evaluation, under the supervision of and with the participation of the APUC’s management, including the Chief Executive Officer (“CEO”) and the Chief Financial Officer (“CFO”), of the effectiveness of the design and operations of APUC’s disclosure controls and procedures (as defined in Rule 13a - 15(e) and Rule 15d - 15(e) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”)). Based on that evaluation, the CEO and the CFO have concluded that as of December 31, 2011, APUC’s disclosure controls and procedures are effective.

Internal controls over financial reporting

APUC’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

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

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

Management conducted an evaluation of the design and operation of APUC's internal control over financial reporting as of December 31, 2011 based on the criteria set forth in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. This evaluation included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls and a conclusion on this evaluation. Based on this evaluation, management has concluded that APUC's internal control over financial reporting was effective as of December 31, 2011.

During the year ended December 31, 2011, there has been no change in APUC's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, APUC's internal control over financial reporting. There was no significant impact of the transition to U.S. GAAP on APUC's internal controls, information technology systems and financial reporting expertise requirements. No financial covenants were impacted by APUC's conversion to U.S. GAAP.

Quarterly Financial Information

The following is a summary of unaudited quarterly financial information for the two years ended December 31, 2011.

Millions of dollars (except per share amounts)	1st Quarter 2011	2nd Quarter 2011	3rd Quarter 2011	4th Quarter 2011
Revenue	$ 71.7	$ 66.8	$ 66.0	$ 72.1
Net earnings /(loss)	5.0	7.3	19.6	(8.5)
Net earnings / (loss) per share	0.05	0.07	0.16	(0.07)
Total Assets	1,175.8	1,177.7	1,263.1	1,282.6
Long term debt*	461.0	530.0	558.9	463.8
Dividend declared per share	0.065	0.065	0.07	0.07

	1st Quarter 2010*	2nd Quarter 2010*	3rd Quarter 2010*	4th Quarter 2010
Revenue	$ 45.9	$ 42.7	$ 45.4	$ 48.4
Net earnings / (loss)	3.5	(2.2)	1.5	15.6
Net earnings / (loss) per share	0.04	(0.02)	0.02	0.17
Total Assets	966.2	983.2	969.4	1,016.9
Long term debt*	434.0	446.7	452.8	450.8
Dividend declared per share	0.06	0.06	0.06	0.06

* Long term debt includes long term liabilities, the Facility, convertible debentures and other long term obligations

The quarterly results are impacted by various factors including seasonal fluctuations and acquisitions of facilities as noted in this MD&A.

Quarterly revenues have fluctuated between $42.7 million and $72.1 million over the prior two year period. A number of factors impact quarterly results including acquisitions, seasonal fluctuations, hydrology and winter and summer rates built into the PPAs. In addition, a factor impacting revenues year over year is the fluctuation in the strength of the Canadian dollar which can result in significant changes in reported revenue from U.S. operations.

Quarterly net earnings have fluctuated between net earnings of $19.6 million and a net loss of $8.5 million over the prior two year period. Earnings have been significantly impacted by non-cash factors such as future tax recovery and expense, impairment of intangibles, property, plant and equipment and mark-to-market gains and losses on financial instruments.

Critical Accounting Estimates and Polices

The preparation of consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, related amounts of revenues and expenses, and disclosure of contingent assets and liabilities. Significant areas requiring the use of management estimates relate to the useful lives and recoverability of depreciable assets, recoverability of deferred tax assets, rate-regulation, unbilled revenue and fair value of derivatives. Actual results may differ from these estimates.

APUC's significant accounting policies are discussed in Note 1 to the consolidated financial statements. Management believes the following accounting policies involve the application of critical accounting estimates. Accordingly, these accounting estimates have been reviewed and discussed with the Audit Committee of the Board of Directors of APUC.

Estimated useful lives and recoverability of Long-Lived Assets and Intangibles

The provisions for depreciation of utility property and equipment for financial reporting purposes are made on the straight-line method based on the estimated service lives of the assets (3 to 75 years). Depreciation rates on utility assets are subject to regulatory review and approval, and depreciation expense is recovered through rates set by ratemaking authorities. The recovery of those costs is dependent on the ratemaking process. Non-regulated property and equipment are depreciated on a straight-line basis over useful lives (3 to 60 years) of the related assets. Management believes the lives and methods of determining depreciation are reasonable, however, changes in economic conditions affecting the industries could result in a reduction of the estimated useful lives of those non-regulated assets or in an impairment write-down of the carrying value of these properties.

The carrying value of long-lived assets, including identifiable intangibles, is reviewed whenever events or changes in circumstances indicate that such carrying values may not be recoverable. Some of the factors APUC considers as indicators of impairment include whether a facility is operating, its plan for return to service, external influences such as natural disasters, energy pricing and profitability and changes in regulation. Unforeseen events and changes in circumstances and market conditions and material differences in the value of long-lived assets and intangibles due to changes in estimates of future cash flows, interest rates, regulatory matters and operating costs could negatively affect the fair value of APUC's assets and result in an impairment charge.

Fair value is the amount at which the asset could be bought or sold in a current transaction between willing parties and may be estimated using a number of techniques, including quoted market prices or valuations by third parties, present value techniques based on estimates of cash flows, or multiples of earnings or revenue performance measures. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

Valuation of Deferred Tax Assets

Income taxes are accounted for using the asset and liability method. Under this method, deferred income taxes are recognized, at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities, as well as operating loss and tax credit carryforwards. The amount of deferred tax assets recognized is limited to the amount of the benefit that is more likely than not to be realized.

In assessing the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized and provides any necessary valuation allowances as required. Although management believes the assumptions, judgments and estimates are reasonable, changes in tax laws and changes in operations could significantly impact the amounts provided for income taxes in our financial statements.

Accounting for Rate Regulation

Accounting guidance for regulated operations provides that rate-regulated entities account for and report assets and liabilities consistent with the recovery of those incurred costs in rates if the rates established are designed

to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. This accounting guidance is applied to Liberty Utilities' operations. Certain expenses and revenues subject to utility regulation or rate determination normally reflected in income are deferred on the balance sheet as regulatory assets or liabilities and are recognized in income as the related amounts are included in service rates and recovered from or refunded to customers. Regulatory assets and liabilities are recorded when it is probable that these items will be recovered or reflected in future rates. Determining probability requires significant judgment on the part of management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders and industry practice. If events were to occur that would make the recovery of these assets and liabilities no longer probable, these regulatory assets and liabilities would be required to be written off or write down. At December 31, 2011, APUC had recorded regulatory assets of $5.0 million and regulatory liabilities of $21.7 million.

Unbilled Energy Revenues

Revenues related to electricity and water delivery are generally recognized upon delivery to customers. The determination of customer billings is based on a systematic reading of meters throughout the month. At the end of each month, amounts of energy or water provided to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recorded. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns compared to normal, total volumes supplied to the system, line losses, economic impacts and composition of customer classes. Estimates are reversed in the following month and actual revenue is recorded based on subsequent meter readings. Historically, any differences between the actual and estimated amounts have been immaterial.

Derivatives

APUC uses derivative instruments to manage exposure to changes in electricity prices and interest rates. Derivative instruments that do not meet the normal purchases and sales exception are recorded at fair value, with changes in the derivative's fair value recognized currently in earnings. Management's judgment is required to determine if a transaction meets the definition of a derivative and, if it does, whether the normal purchases and sales exception applies or whether individual transactions qualify for hedge accounting treatment. Management's judgment is also required to determine the fair value of derivative transactions. APUC determines the fair value of derivative instruments based on forward market prices in active markets adjusted for nonperformance risk. A significant change in estimate could affect APUC's results of operations.

Additional disclosure of APUC's critical accounting estimates is also available SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com.

Changes in Accounting Policies

Accounting Framework

The Consolidated Financial Statements and accompanying notes have been prepared in accordance with U.S generally accepted accounting principles in the United States ("U.S. GAAP") and follow disclosures required per Regulation S-X provided by the Securities and Exchange Commission ("SEC") Guidance. These are APUC's first U.S. GAAP annual consolidated financial statements.

APUC's consolidated financial statements were prepared in accordance with Canadian Generally Accepted Accounting Principles ("Canadian GAAP") until December 31, 2010. Canadian GAAP differs in some areas from U.S. GAAP as was disclosed in the reconciliation to U.S. GAAP included in the annual consolidated financial statements for the year ended December 31, 2010. Descriptions of the effect of the transition from Canadian GAAP to U.S. GAAP on APUC's financial position, financial performance and cash flows as at and for the two years ended December 31, 2010 are provided in note 24 of the consolidated financial statements for the year ended December 31, 2010. The accounting policies set out in the annual Consolidated Financial Statements for the year ended December 31, 2011 have been consistently applied to all the periods presented. The comparative figures in respect of 2010 were restated to reflect the adoption of U.S. GAAP.

APUC has retrospectively adopted U.S. GAAP as its financial reporting accounting framework starting in 2011. U.S. GAAP reporting is permitted by Canadian securities laws and for companies listed on the TSX which are subject to reporting obligations under U.S. securities laws as an alternative to adoption of International Financial Reporting Standards ("IFRS"). APUC has concluded that U.S. GAAP is the accounting framework that provides its shareholders and other readers of its financial statements the most useful and relevant basis for financial reporting given the significance of its rate regulated businesses. U.S. GAAP includes accounting standards for rate-regulated activities within the financial statements. Except where otherwise indicated, comparative amounts in this MD&A have been restated from the amounts previously reported under Canadian GAAP.

Exhibit 99.4



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INDEPENDENT AUDITORS' REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Algonquin Power & Utilities Corp.

We have audited the accompanying consolidated financial statements of Algonquin Power & Utilities Corp., which comprise the consolidated balance sheets as at December 31, 2011 and December 31, 2010, the consolidated statements of operations, comprehensive income (loss), equity, and cash flows for the years ended December 31, 2011 and December 31, 2010, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with U.S. generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Algonquin Power & Utilities Corp. as at December 31, 2011 and December 31, 2010, and its consolidated results of operations and its consolidated cash flows for the years ended December 31, 2011 and December 31, 2010, in accordance with U.S. generally accepted accounting principles.

Other Matter

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Algonquin Power & Utilities Corp.'s internal control over financial reporting as of December 31, 2011, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 21, 2012 expressed an unmodified (unqualified) opinion on the effectiveness of Algonquin Power & Utilities Corp.'s internal control over financial reporting.

/s/ KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada

March 21, 2012

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Algonquin Power & Utilities Corp.

We have audited Algonquin Power & Utilities Corp.'s internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Algonquin Power & Utilities Corp.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in management's report on internal control over financial reporting in the annual report on Form 40-F. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Algonquin Power & Utilities Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Algonquin Power & Utilities Corp. as of December 31, 2011 and December 31, 2010, and the related consolidated statements of operations, comprehensive income (loss), changes in equity, and cash flows for the years ended December 31, 2011 and December 31, 2010, and our report dated March 21, 2012 expressed an unqualified (unmodified) opinion on those consolidated financial statements.

/s/ KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada

March 21, 2012

Exhibit 99.5



KPMG LLP
Chartered Accountants
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Consent of Independent Registered Public Accounting Firm

We consent to the inclusion in this annual report on Form 40-F of:

- our Independent Auditors' Report dated March 21, 2012 on the consolidated financial statements of Algonquin Power & Utilities Corp. ("the Company"), which comprise the consolidated balance sheets as at December 31, 2011 and December 31, 2010, the consolidated statements of operations, comprehensive income (loss), equity and cash flows for the years ended December 31, 2011 and December 31, 2010, and notes, comprising a summary of significant accounting policies and other explanatory information;
- our Independent Auditors' Report of Registered Public Accounting Firm dated March 21, 2012 on the consolidated financial statements of the Company, which comprise the consolidated balance sheets as at December 31, 2011 and 2010, the consolidated statements of operations, comprehensive income (loss), equity and cash flows for the years ended December 31, 2011 and December 31, 2010, and notes, comprising a summary of significant accounting policies and other explanatory information; and,
- our Report of Independent Registered Public Accounting Firm dated March 21, 2012 on the Company's internal control over financial reporting as of December 31, 2011

each of which is contained in this annual report on Form 40-F of the Company for the fiscal year ended December 31, 2011.

/s/ KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada
March 30, 2012

Exhibit 99.6

CERTIFICATION PURSUANT TO SECTION 302 OF THE U.S. SARBANES-OXLEY ACT OF 2002

I, Ian E. Robertson, certify that:

1. I have reviewed this annual report on Form 40-F of Algonquin Power & Utilities Corp.

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: March 30, 2012

By: /s/ Ian E. Robertson
Name: Ian E. Robertson
Title: Chief Executive Officer

Exhibit 99.7

CERTIFICATION PURSUANT TO SECTION 302 OF THE U.S. SARBANES-OXLEY ACT OF 2002

I, David Bronicheski, certify that:

1. I have reviewed this annual report on Form 40-F of Algonquin Power & Utilities Corp.

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: March 30, 2012

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

Exhibit 99.8

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Algonquin Power & Utilities Corp. (the "Corporation") on Form 40-F for the year ended December 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Ian E. Robertson, Chief Executive Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Corporation.

Date: March 30, 2012

By: /s/ Ian E. Robertson
Name: Ian E. Robertson
Title: Chief Executive Officer

Exhibit 99.9

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Algonquin Power & Utilities Corp. (the "Corporation") on Form 40-F for the year ended December 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, David Bronicheski, Chief Financial Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Corporation.

Date: March 30, 2012

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