ALGONQUIN POWER & UTILITIES CORP.

ANNUAL INFORMATION FORM

March 31, 2011
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All information contained in this Annual Information Form ("AIF") is presented as at March 31, 2011, 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 Hydrogénique, 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”) 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 is continuing the business of Algonquin Power Income Fund (“Algonquin” or the “Fund”). APUC’s principal holdings are its trust units (“Trust Units”) of Algonquin Power Co. (“APCo”), shares of Liberty Water Co. (“Liberty Water”) and shares of Liberty Energy Utilities Co. (“Liberty Energy”).

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 principle holding for APUC’s independent power generation business is an investment in 100% of the issued and outstanding Trust Units of APCo. The principle 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, a Delaware corporation, which in turn owns both Liberty Water and Liberty Energy. Each of APCo, Liberty Water and Liberty Energy have their own subsidiaries and ownership chains.

The subsidiaries of APCo include the ownership chains of Algonquin Power Trust (“APT”), Algonquin Power Operating Trust (“APOT”), Algonquin Power Fund (Canada) Inc. (“APFC”) and Algonquin Power Fund (America) Inc. (“APFA”). The Liberty Energy chain is currently structured to hold the electric utility assets located in California and acquired January 1, 2011, and the Liberty Water chain is structured to hold the water and wastewater assets located in the United States. These major chains are defined and shown in the chart below, and a detailed description of the legal entities that comprise these chains and the Facilities they own is then provided. Additional information on the Facilities is described in Schedules A, B, C and D.
(i) APCo Chain Entities

APCo is the sole beneficiary of APT, which owns all the Trust Units of APOT. 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 controls the entities that own some of the Canadian hydroelectric facilities, and the energy-from-waste facility (the “EFW Facility”) located in the Regional Municipality of Peel, Ontario (“Peel”). 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 wind facility located at St. Leon, Manitoba (the “St. Leon Facility”), one hydroelectric facility in Alberta (the “Dickson Dam Facility”) and APCo’s 50% interest in the Alberta biomass facility (the “Valley Power Facility”). APCo also owns Algonquin Holdco Inc., an Ontario corporation, which owns APFC. APFC was incorporated in Nova Scotia and it controls the entities that own the majority of the hydroelectric facilities in Canada. APFC also owns APFA, a Delaware corporation, which is the top APCo entity in the United States. APFA owns and controls the U.S. hydroelectric entities, and also controls the entities that own the U.S. thermal cogeneration facilities known as the Sanger Facility and the Windsor Locks Facility.

(ii) APT Group

APT forms part of the APCo business unit and indirectly owns the EFW Facility in the city of Brampton located in 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”). It 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. Ulrich Wind Energy Investments L.P. (“St. Ulrich LP”), a Québec limited partnership, through its ownership of the limited partnership of St. Ulrich LP, (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 Éoliennes St-Laurent Inc. (“Corporation St-Laurent”), a Québec corporation. Corporation St-Laurent Inc. 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 “Power Generation - New Wind Projects Under Development”. 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 “Power Generation - New Wind Projects Under Development”. It owns a 25% equity interest in the general partner, 9231-5498 Québec Inc. and it also holds a 24.9975% limited partner interest.

(iii) APOT Group

The APOT entities that own the BCI Facility are 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.

The APOT entity that owns the St. Leon Facility is St. Leon Wind Energy LP, an Ontario partnership (“St. Leon LP”). It is owned 26.43% by the general partner, St. Leon Wind Energy GP Inc. (“St. Leon GP”), 73.16% by St. Leon Wind Energy Trust, a Manitoba trust ("St. Leon Trust") and 0.42% by AirSource Power Fund I LP, a Manitoba limited partnership ("AirSource"). St. Leon LP has issued 100 Class B limited partnership units. Two executives of APUC, Ian Robertson and Christopher Jarratt (the “Senior Officers”) 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. 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 also the sole limited partner in St. Leon II Wind Energy LP, a Manitoba partnership, the general partner of which is St. Leon II Wind Energy GP Inc. 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 the Dickson Dam Facility. Second, it 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 Valley Power Facility. APOT directly holds a further 49.9995% limited partnership interest in Valley Power LP.

(iv) APFC Group

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 as to 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 (Rattle Brook) 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.

(v) APFA Group

APFA owns Algonquin Power Sanger LLC (“Sanger LLC”), a California limited liability company, and Algonquin Power Windsor Locks 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, Lakeport and Milton Facilities are owned by, respectively, Franklin Power, LLC, a New Hampshire company, Algonquin Power (Beaver Falls) LLC, a Delaware corporation, Lakeport Hydroelectric Corp., a New Hampshire corporation, and SFR Hydro Corporation, a New Hampshire company. 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 1% by Algonquin Holdco and 99% by APFA.

APFA, in January 2010, 100% acquired two entities, now known as 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. leases the 36.8MW of electrical generating assets in New Brunswick (the "Tinker Assets") from APT, and Northern Maine Gen Co. is the owner of the Caribou, Squa Pan and Flos Inn hydro, diesel and steam 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’s business primarily involves providing the electrical energy requirements for commercial and industrial customers in northern Maine. On February 4, 2010, AES acquired a number of load supply and energy procurement contracts in northern Maine and the Independent System Operator New England ("ISO-NE") market (the “Energy Services Business”). See “Significant Acquisitions” in “General Development of the Business” and “Energy Services Business” in “Description of the Business”.

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.

(vi) Liberty Water Group

On December 22, 2010, APCo completed a corporate reorganization involving Liberty Water wherein 100% of the issued and outstanding common shares of Liberty Water were transferred to APUC at their estimated fair market value which approximated the book value of the shares. Liberty Water was originally formed under the laws of the state of Delaware as Algonquin Water Resources of America, Inc. The name was changed on April 28, 2009 to Liberty Water Co. Liberty Water Co. forms the top of the Liberty Water Group and 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 the Entrada Del Oro Sewer Company, Inc. ("Entrada") in which it currently operates and 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 Galveston, 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 and Timber Creek resorts. 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.

(vii) Liberty Energy Group

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"). Effective January 1, 2011, Calpeco acquired the California-based electricity distribution and related generation assets of NV Energy, Inc. ("NV Energy"). See “Significant Acquisitions”. Liberty Energy also owns Liberty Energy Utilities (New Hampshire) Corp. ("Liberty Energy NH"), a Delaware corporation registered in New Hampshire. Liberty Energy NH is the named purchaser of the shares of Granite State Electric Company ("Granite State") and EnergyNorth Natural Gas Inc. ("EnergyNorth") currently owned by for the assets of National Grid USA ("National Grid").

(viii) Other

Outside of the APCo, Liberty Water and Liberty Energy chains described above, APUC beneficially owns, directly or indirectly 100% of the following: 3793257 Canada Inc. ("3793257"), a corporation incorporated under the CBCA; and Windlectric Inc. ("Windlectric"), a federal corporation that is developing the Amherst Island wind project, described below in “Power Generation - New Wind Projects Under Development”.

(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 the Fund on April 17, 1998.
2. GENERAL DEVELOPMENT OF THE BUSINESS

2.1 General

(a) The Unit Exchange

On October 27, 2009, Algonquin completed a transaction (the “Unit Exchange”) in which Algonquin’s unitholders exchanged their trust units of Algonquin, on a one-for-one basis, for Common Shares of an existing corporation. As a result of the Unit Exchange, the Fund itself became a wholly-owned subsidiary of the Corporation and all of the unitholders of the Fund became shareholders of the Corporation. The Unit Exchange did not result in any change to the underlying business operations of the Fund and accordingly, for accounting purposes, the Corporation is considered a continuation of the Fund. The Fund has since changed its name to Algonquin Power Co.

(b) Business Strategy

APUC’s business strategy is to maximize long term shareholder value as a dividend paying, growth-oriented corporation in the power and utilities business sectors. APUC is committed to delivering a total shareholder return comprised of dividends augmented by capital appreciation arising through growth in dividends 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 5% and to grow its dividend supported by growth in cash flows, earnings and investment prospects.

APUC understands the importance of the dividend to its shareholders. In the fiscal year ended December 31, 2010, APUC paid quarterly cash dividends to shareholders of $0.06 per share or $0.24 per share per annum. On March 3, 2011, the board of directors of APUC (the “Board”) approved an annual dividend increase of $0.02 per common share for a total annual dividend of $0.26, paid quarterly at a rate of $0.065 per common share. The Board also declared a dividend of $0.065 per share payable on April 15, 2011 to the shareholders of record on March 31, 2011.

APUC believes this level of dividends will continue to allow 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. Any increases in the level of dividends paid by APUC will be at the discretion of 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 the Corporation. APUC strives to achieve its results within 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 develops, owns and operates a diversified portfolio of electrical energy generation facilities. Within this business there are three distinct divisions: Renewable Energy, Thermal Energy and Development. The Renewable Energy division operates APCo’s hydroelectric and wind power facilities. The Thermal Energy division operates co-generation, energy-from-waste, and steam production facilities. The Development division seeks to deliver continuing growth to APCo through development of APCo’s greenfield power generation projects, accretive acquisitions of electrical
energy generation facilities as well as development of organic growth opportunities within APCo’s existing portfolio of renewable energy and thermal energy 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 involves building on APCo’s expertise in the origination of greenfield renewable energy projects, expanding APCo’s existing portfolio of 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. As at March 15, 2011, APCo owns or has interests in 44 hydroelectric facilities operating in Ontario (4), Québec (12), Newfoundland (1), New Brunswick (1) Alberta (1), New York State (13), New Hampshire (8), Vermont (1), Maine (2) and New Jersey (1) with a combined generating capacity of approximately 165 MW. APCo also owns a 104 MW wind powered generating station in Manitoba and holds debt securities in a 26 MW wind powered generating station recently completed in Saskatchewan. Approximately 75% of the installed capacity of APCo’s renewable energy facilities sell their electrical output pursuant to long term power purchase agreements (“PPAs”) with major utilities and have a weighted average remaining contract life of 16 years.

APCo’s Thermal Energy division holds equity interests in one energy-from-waste facility in Ontario with an installed generating capacity of 10 MW, 4 diesel generating facilities in Maine and New Brunswick with total installed generating capacity of 34 MW and 3 natural gas-fired cogeneration facilities in each of California, Connecticut, and Ontario with an installed capacity of approximately 112 MW. In addition, APCo’s Thermal Energy division owns partnership, share and debt interests in two biomass-fired generating facilities with combined installed capacity of approximately 43 MW located in Alberta and Québec. APCo’s Thermal Energy division holds minority investments in two natural gas/wood waste-fired generating facilities with joint installed capacity of approximately 170 MW located in northern Ontario. APCo’s ownership interest in the combined installed generating capacity represents approximately 210 MW. APCo’s thermal energy facilities operate under long term PPAs with major utilities and have an average remaining contract life of 6 years. Detailed information on the facilities owned and operated by APCo is set out in Schedules A and B.

Utilities: Liberty Utilities Co. (“Liberty Utilities”) owns and operates utilities through its two wholly-owned subsidiaries, Liberty Energy and Liberty Water. Liberty Energy is in the electricity distribution, transmission and generation sector as well as natural gas distribution. Liberty Water is in the water distribution and wastewater treatment sector. These utilities share certain common infrastructure to generate economies of scale to support best-in-class customer care for its utility ratepayers. 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’ water utility division operates under the name of Liberty Water. Liberty Water provides water and wastewater utility services to approximately 74,000 customers through 19 water distribution and wastewater collection and treatment utility systems located in four U.S. States (Arizona (8), Illinois (1), Missouri (3) and Texas (7)). 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 Water is set out in Schedule C.
In 2009, APUC branded all of its water and wastewater utilities under the Liberty Water brand. Liberty Water 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 Water delivers long term value by profitably owning and operating water and wastewater utilities while providing safe, reliable transportation and delivery of water and wastewater treatment in its service areas. It is also focused on delivering continued growth in earnings by identifying opportunities which accretively expand its business portfolio.

Liberty Utilities’ energy utility division operates under the name of Liberty Energy. Liberty Energy provides local electrical and natural gas utility services. On January 1, 2011, Liberty Energy acquired a 50.001% interest in a California-based electricity distribution utility and related generation assets, and now provides electric distribution service to customers in the Lake Tahoe region (the “California Utility”). Liberty Energy has entered into agreements to acquire two additional utilities which currently provide electric and natural gas distribution services to customers in New Hampshire. Detailed information on the electrical utilities systems owned and operated by Liberty Energy is set out in Schedule D.

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 2008

On January 16, 2008, the Fund renewed its combined $175.0 million senior secured revolving operating and acquisition credit facility (the “Senior Credit Facility”) with a syndicate of Canadian banks. Under terms of the renewal, the Senior Credit Facility was extended for a three year term with a maturity date of January 14, 2011. The renewal included improved pricing and other terms as well as an accordion feature that, subject to certain conditions, allowed the Senior Credit Facility to increase to $225.0 million to accommodate future growth and acquisitions. The Fund subsequently exercised a portion of the accordion feature, resulting in total committed and available Senior Credit Facility of $192.8 million.

In June 2008, the BCI Facility was commissioned and became operational. The project involved diverting the existing steam produced by the EFW Facility to a nearby recycled paper board manufacturing mill that requires approximately 90,000 pounds of steam per hour in its manufacturing activities. BCI was established to supply steam produced through normal operations at the EFW Facility to this mill.

On June 27, 2008, the Fund entered into a business combination agreement (the “Business Combination Agreement”) with Highground Capital Corporation (“Highground”) and CJIG Management Inc. (“CJIG”), the manager of Highground and a related party of the Fund controlled by the shareholders of Algonquin Power Management Inc. (“APMI”). APMI was the manager of APCo up to December 22, 2009 and two executives of APUC, the Senior Executives, are principals of APMI. Pursuant to the Business Combination Agreement, CJIG acquired all of the issued and outstanding common shares of Highground, and the Fund issued approximately 3.5 million Trust Units at an ascribed value of approximately $7.69 per Trust Unit. The trading price of the Trust Units at the time of issue was $7.41.

In June 2008, the BCI Facility was commissioned and became operational. The project involved diverting the existing steam produced by the EFW Facility to a nearby recycled paper board manufacturing mill that requires approximately 90,000 pounds of steam per hour in its manufacturing activities. BCI was established to supply steam produced through normal operations at the EFW Facility to this mill.

On June 27, 2008, the Fund entered into a business combination agreement (the “Business Combination Agreement”) with Highground Capital Corporation (“Highground”) and CJIG Management Inc. (“CJIG”), the manager of Highground and a related party of the Fund controlled by the shareholders of Algonquin Power Management Inc. (“APMI”). APMI was the manager of APCo up to December 22, 2009 and two executives of APUC, the Senior Executives, are principals of APMI. Pursuant to the Business Combination Agreement, CJIG acquired all of the issued and outstanding common shares of Highground, and the Fund issued approximately 3.5 million Trust Units at an ascribed value of approximately $7.69 per Trust Unit. The trading price of the Trust Units at the time of issue was $7.41. Of these Trust Units, approximately 3.1 million Trust Units were received by shareholders of Highground as part of the Business Combination Agreement, with the remaining Trust Units being retained by CJIG. The Fund recorded the Trust Units issued at the estimated fair value of the assets to be liquidated by Highground which, net of transaction costs of $0.8 million, resulted in proceeds of the Trust Units being recorded at a value of $26.2 million. In connection with this transaction, the Fund received: (a) net cash
in an amount of $20.6 million; (b) the return of notes, having an aggregate face value of approximately $4.8 million, that were issued by the Fund affiliates related to its St. Leon and BCI Facilities; and (c) a note receivable of $0.8 million related to a hydroelectric facility in Ontario.

The final consideration for the Trust Units is dependent on the proceeds realized from the liquidation of certain Highground investments. APUC’s final consideration will be equal to the lesser of (a) $27.0 million plus 50% of the amount, if any, of the value of the assets formerly owned by Highground after payment of the transaction costs that exceeds $27.0 million and (b) the value of all of the assets formerly owned by Highground after payment of the transaction costs. The value of any non-cash securities received by APUC will be determined through negotiation between the Board and CJIG. The remaining investments, formerly held by Highground, consist primarily of non-liquid debt assets having a book value of approximately $3.2 million. APUC is entitled to 50% of the ultimate proceeds from these investments, after certain adjustments for transaction costs.

(b) Fiscal 2009

On October 27, 2009, the Fund and the Corporation completed the Unit Exchange. See “The Unit Exchange”. As part of the Unit Exchange, on October 27, 2009, the trustees of the Fund also became directors of APUC.

Also on October 27, 2009, in connection with the Unit Exchange, the debentureholders of the Fund exchanged their convertible debentures for convertible debentures of the Corporation or Common Shares. As a result, the debentureholders of the Fund became debentureholders and shareholders of the Corporation. See “Capital Structure - Convertible Debentures”.

On December 2, 2009, APUC completed a public offering of 5,980,000 Common Shares at a price of $3.35 per Common Share for gross proceeds of approximately $20 million and approximately $55 million principal amount of 7% convertible unsecured subordinated debentures due June 30, 2017 (the “Series 3 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 “Capital Structure - Convertible Debentures”.

On December 21, 2009, the board of directors of the Corporation (the “Board”) reached agreement with the shareholders of APMI to internalize all management functions of the Fund which were provided by 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.

(c) Fiscal 2010

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

Liberty Water had ongoing rate cases at a number of its utilities which were processed throughout 2010. See “Utilities: Water and Wastewater - Rate Cases” for further discussion of the status of these rate cases. During the year ended December 31, 2010, Liberty Water 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 Liberty Water. 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 is expected to be concluded by the first quarter of 2011.

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 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 the Senior Credit Facility.

2.3 Recent Developments

(a) Power Generation - New Wind Projects Under Development

75 MW Wind - Amherst Island: On February 25, 2011, APUC announced that the Ontario Power Authority (“OPA”) awarded a contract to the wholly-owned 75 MW Amherst Island Wind Project. The Amherst Island Wind Project is located on Amherst Island in the village of Stella, approximately 25 kilometres southwest of Kingston, Ontario. The contract was awarded as part of the second round of the OPA’s Feed-in Tariff (“FIT”) program. Construction is expected to commence shortly following the approval of the application and is expected to take 12 months.

(b) Power Generation: Development

25MW Wind – 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 APUC. The first 24 MW phase of the project currently has a targeted commercial operations date in late 2013.

25 MW Wind - 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 APUC. The first 24 MW phase of the project currently has a targeted commercial operations date of late 2015.

Preliminary permitting began for both projects in early 2011, with all major authorizations targeted for completion by the end of 2012.

20 MW Wind - Morse: On March 21, 2011, APUC announced it has executed an asset purchase agreement with Kineticor Renewables Inc. (“Kineticor”), to acquire all of the assets related to two proposed adjacent 10 MW wind energy development projects near Morse, Saskatchewan (the “Morse Projects”). The Morse Projects are approximately 180 km west of Regina and 400 km west of the 26.4 MW wind generation facility in southeastern Saskatchewan (“Red Lily I”).

The Morse Projects were selected by SaskPower for award of PPAs in accordance with the SaskPower Green Options Partners Program in May 2010. Upon SaskPower’s approval and execution of the PPAs, Kineticor will assign the PPAs to APCo. The Morse Projects are expected to be completed in late 2013.

The Morse Projects are approximately 180 km west of Regina and 400 km west of the 26.4 MW wind generation facility in southeastern Saskatchewan (“Red Lily I”). It is contemplated that the Morse Projects will be situated on 1,120 acres of private lands, with additional land under lease or option in order to facilitate future expansion of the Morse Projects.
For a more detailed description of the current projects under development, see “Current Development Projects” and “Quebec Community Wind Projects” in the section entitled “Power Generation: Development” below.

(c) Power Generation

On February 28, 2011, APUC announced that Red Lily I commenced commercial operation under the SaskPower PPA. The PPA with SaskPower is for 25 years and includes a 2% annual increase throughout the term of the agreement. APUC’s commitment in Red Lily I is structured in the form of senior and subordinated debt investment of approximately $19.6 million bearing a blended interest rate of 8.43%.

Project construction costs at Red Lily I are expected to total $71.2 million. In addition to interest payments on its portion of the debt financing, APUC is entitled to certain supervisory fees, estimated at $1.3 million in the first full year of operation. Total interest and fee payments to APUC in 2011 are estimated to be approximately $2.4 million, 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.

For a more detailed description of the options and expected impact see “Red Lily Facility” under “Material Facilities” in the section entitled “Power Generation: Renewable – Wind Power” below.

Subsequent to December 31, 2010, the Energy Services Business entered into a three year contract with Maine Public Service Company, 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.

The capital upgrade at the EFW Facility, completed in July 2010, is expected to result in higher throughput and lower operating costs at the Facility in the first quarter of 2011 as compared to the same period in 2010 when the Facility was temporarily shut down as a result of an unplanned outage experienced in January 2010.

The Windsor Locks 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 retail customers through the Energy Services Business. The Facility did not commit any portion of its electrical capacity to the forward reserve market for the winter of 2011 due to unacceptably low auction prices. It is anticipated that performance during the first quarter of 2011 will be strong, resulting from moderate natural gas prices and a cold winter in the north-east U.S. that has resulted in high electricity prices. APCo has completed preliminary engineering for a repowering project at the Windsor Locks Facility and is in negotiations with Ahlstrom Windsor Locks, LLC (“Ahlstrom”) regarding this project. For a more detailed description of the options and expected impact see “Windsor Locks” under “Material Facilities” in the section entitled “Cogeneration” below.

(d) Senior Credit Facility

On January 14, 2011, APUC announced that it has received commitments from a syndicate of Canadian banks for a new $142 million Senior Credit Facility with a three year term. Under the terms of the new banking agreement, as at December 31, 2010, APCo had $44.4 million of committed and available bank facilities remaining and $5.1 million of cash resulting in $49.5 million of total liquidity and capital reserves. The APCo Senior Credit Facility now matures on February 14, 2014.
As at March 25, 2011, APCo had used the Senior Credit 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 $2.3 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 Amherst Island Wind Project totalling $1.5 million; and (viii) various other letters of credit required by APCo entities totalling $1.1 million.

(e) Liberty Water

On December 11, 2010, the Arizona Corporate Commission (“ACC”) approved an order authorizing a rate increase of U.S. $0.9 million for the Rio Rico Facility, effective February 1, 2011. It is anticipated that the regulatory review of the proposed rates and tariffs for the Bella Vista, Northern Sunrise, and Southern Sunrise Facilities will be completed in Q1 2011. Total revenue increases from rate cases completed in Arizona and Texas represent an additional U.S. $10.2 million in annualized revenue. As these rate cases were settled at various times throughout the year ended December 31, 2010, approximately U.S. $2.3 million of the overall annualized revenue increase from rate cases completed in Arizona and Texas was achieved in the year.

(f) Liberty Energy

In 2009, APUC announced plans to acquire the California Utility assets in partnership with Emera Inc. (“Emera”). The acquisition was approved by both the California Public Utilities Commission (“CPUC”) and the Public Utilities Commission of Nevada in the fourth quarter of 2010. The transaction was completed on January 1, 2011 for a purchase price of approximately U.S. $131.8 million, subject to certain working capital and other closing adjustments. The acquisition was funded in part with the proceeds of a U.S. $70 million senior unsecured private debt placement at the utility. Liberty Energy’s ownership share of the cost of acquisition of the California Utility was primarily funded through the proceeds of subscription receipts held by Emera for 8.532 million APUC Common Shares at a price of $3.25 per share.

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 for total consideration of U.S. $285.0 million. See “Significant Acquisitions - Energy Utilities”.

Liberty Energy is pursuing additional investments in electric and gas distribution utilities and electric transmission assets, sharing certain common infrastructure between utilities to support best in-class-customer care for its subsidiary utility ratepayers.

2.4 Significant Acquisitions

(a) Power Generation

On January 12, 2010, APCo completed the acquisition of three hydroelectric generating stations, the 34.5MW Tinker Hydro Facility, a 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, Caribou Hydro Facility, a 0.9MW run-of-river hydroelectric generating facility located in Northern Maine and Squa Pan Hydro Facility, a 1.4MW run-of-river hydroelectric generating facility located in Northern Maine.
APCo also acquired five thermal generating facilities with a rated capacity of 40MW 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, ISO-NE).

In connection with the acquisition of the Tinker Assets, on February 4, 2010, APCo acquired the Energy Services Business which markets the energy generated from the Tinker Assets. It is anticipated that the majority of the energy sold by the Energy Services Business will be supplied through generation from the Tinker Assets, based on historical long term average levels of hydroelectric energy generation of these facilities. The Energy Services Business 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.

The Energy Services 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.

(b) Energy Utilities

On April 23, 2009, APUC announced plans 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 asset purchase agreement by and between Sierra Pacific Power Company d/b/a NV Energy and Calpeco dated April 22, 2009 (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 48,000 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 the Fund 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 8.532 million Common Shares at a purchase price of $3.25 per Common Share. The proceeds of the subscription receipts were utilized to fund Liberty Energy’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, backed solely by the California Utility assets. The notes are fixed rate and split into two tranches, U.S. $45 million of ten year 5.19% notes and U.S. $25 million of 5.59% fifteen year notes.
On December 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 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”).

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.

Closings of the transactions are subject to certain conditions including state and federal regulatory approval, and are expected to occur in the fall of 2011. 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 December 9, 2010 (the “2010 Subscription Agreement”), Emera has agreed to a conditional treasury subscription of 12.0 million trust units of APUC at a price of $5.00 per Common Share representing an approximate 5% premium to APUC’s closing share price on December 8, 2010. 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.

For complete details on the Purchase Agreement(s) and the Subscription Agreement, reference should be made to the documents as filed on SEDAR at www.sedar.com.

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.

Most recently in 2007, the 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. The ecoEnergy program is scheduled to be completed by the end of March 2011.

(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. Public Utilities Regulatory Policies Act ("PURPA"). FERC, pursuant to the PURPA legislation, mandates the development of policies by state utility commissions and utilities themselves that enable private producers to build power facilities. The key policy issue was the development of long term PPAs with fixed, long-term power purchase rates. The long-term rates were based on projections of the utilities’ Avoided Costs. “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. Today, due to market forces and economic changes, many of these long-term agreements are priced far above current market rates. While these higher costs are burdensome to the utilities, most have recognized these as costs incurred prior to deregulation that can no longer be paid by the rate base due to changes to various factors.

On February 2, 2006, PURPA issued revised rules, Revised Regulations Governing Small Power Production and Cogeneration Facilities, Order No. 671, 114 FERC 61,102 (2006). Further regulations were also issued to clarify the regulations and became effective on April 20, 2006. In order to comply with the new regulations, in June of 2006, APUC filed with FERC a notification of holding company status for each direct and indirect subsidiary company of APUC. Based on an initial review of the regulations, APFC may be impacted by the revised rules. APUC is currently investigating the option of filing an exemption or waiver with FERC for APFC.

The key regulations that impact APUC are:

1. Any type of Qualifying Facility that exists but has never filed a self-certification (or obtained an order certifying it as a Qualifying Facility) must file a self-certification (or petition for an order) within 60 days of Order No. 671. Self-certification documents were filed for all affected APUC Facilities in compliance with this regulation.

2. Any cogeneration Qualifying Facility, any small power production Qualifying Facility less than 30 MW, and any geothermal small power production Qualifying Facility, is now subject to rate regulation under Section 205 and 206 of the Federal Power Act. However, sales of energy or capacity made by Qualifying Facilities 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 scrutiny under sections 205 and 206. If this exception does not apply, then these Qualifying Facilities must make a rate filing under section 205 of the Federal Power Act in order to be eligible to sell electricity. Rate filings were required to be made on or before the effective date of Order 671, which was March 4, 2006. All relevant APUC facilities had PPAs in place predating this section of the new FERC regulations and as such have not been impacted.

The Obama-Biden New Energy for America Plan supports 10% of electricity in the United States being generated from renewable sources by 2012 and 25% by 2025. The demand for additional renewable power is also expected to increase from the desire by various government entities to increase infrastructure spending.
(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, 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, 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 of 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**

Electrical power generators in Alberta are regulated by the *Electric Utilities Act (Alberta)* and the *Independent Power and Small Power Regulation*.

(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 such PPAs. This Ontario government agency 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 *Energy Act (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 with the aim of selling off the various components. 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. 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.

As a result of the assessments and preliminary evaluation of the associated remedial work, APCo currently estimates it will incur capital expenditures of approximately $17.1 million related to compliance with the legislation. APCo anticipates that these expenditures will be required to be invested over the next five years as follows:

<table>
<thead>
<tr>
<th>Estimated Capital Expenditures</th>
<th>Total</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>$17,100</td>
<td>800</td>
<td>5,000</td>
<td>5,500</td>
<td>3,000</td>
<td>2,800</td>
</tr>
</tbody>
</table>

The majority of these capital costs are associated with the Donnacona, St. Alban, Belleterre and Mont-Laurier Facilities. APCo does not anticipate any significant impact on power generation or associated revenue while the dam safety work is ongoing. APCo is also exploring several alternatives to mitigate the capital costs of modifications, including cost sharing with other stakeholders and revenue enhancements which can be achieved through the modifications.

(iii) Material Facilities

(1) Long Sault Rapids Facility

The Long Sault Rapids Facility is an 18,000 kilowatt 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 Long Sault hydroelectric generating 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) Power Purchase Agreement

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 $39.9 million at December 31, 2010. 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 December 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, 2010, the debt reserve was fully funded using the irrevocable letter of credit.

In addition, APCo owns the LSR Subordinate Note.
(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 11,120 kilowatts. The Côte Ste-Catherine Facility is owned by the Mont-Laurier Partnership.

i) **Land and Water Rights**

The land and water rights necessary for the construction and operation of the Côte Ste-Catherine Facility have been obtained from the St. Lawrence Seaway Authority by way of a lease agreement with the Province of Québec dated March 1, 1988, as amended. In 2009, the existing water rights lease was renewed for an additional term of 21 years commencing March 1, 2009. Although the Facility is located on a federal waterway, the 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”.

(3)  
**Mont Laurier Facility**

The Mont Laurier Facility is a 2,725 kilowatt hydroelectric generating facility located on the Rivière-du-Lièvre in the Town of Mont Laurier, Québec. The Mont Laurier Facility is owned by the Mont-Laurier Partnership.

i) **Land and Water Rights**

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, Power Purchase Agreements - 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 one diesel generator; the total
nameplate capacity of the station equals 34.5 MW. Unit 5 of the Tinker Facility is currently operating as a fixed bladed runner. Historical gross generation from the station averages 128,000 MW-hrs per year. The Tinker Facility benefits from the flow regulation of the Millinocket and 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) Power Purchase Agreements

The Tinker Facility supplies approximately 31,500 MW-hrs per year to the municipal utility of Perth-Andover under a power purchase and sale agreement. The remaining generation from the plant, approximately 100,000 MW-hrs per year, is sold to AES, which provides energy 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 Dickson Dam Facility is a 15.0 MW hydroelectric generating facility utilizing the infrastructure located at the Dickson Dam and powered by the waterflows 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) Power Purchase Agreement

The Dickson Dam PPA was entered into with TransAlta Utilities Corporation ("TransAlta") on December 7, 1990 and was approved by the Alberta Public Utilities Board on January 16, 1991. It has a term of 20 years ending on January 16, 2012. Under this agreement, TransAlta is obligated to accept delivery of all electricity in amounts up to 115% of the 12.7 MW capacity which is allocated to the Facility at rates stipulated by the Small Power Act.

ii) Use of Works Agreement

The Dickson Dam Facility is subject to a Use of Works Agreement with the Government of Alberta under which it has the right to utilize available waterflows 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.

(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) Power Purchase Agreement

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, 2010, 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 a senior loan to the St. Leon Trust to finance construction of the St. Leon Facility. The loan has an amount of $68.7 million outstanding as at December 31, 2010 and matures in October 2011. The senior loan bears interest at banker’s acceptance rate plus a banking charge of 1%, payable monthly. St. Leon Trust has entered into a fixed for floating interest rate swap arrangement until September 2015 to fix the interest on the loan at 4.47%. The loan is secured solely by the facility and the ownership interests therein.

(2) Red Lily I

Red Lily I is a 26.4 MW wind generation facility located 5 kilometres west of Moosomin, Saskatchewan. Red Lily I consists of 16 Vestas V82 wind turbine generators. The equity in Red Lily I is owned by an independent investor, Concord Pacific Group. APUC has a senior debt investment in the facility which will be $13 million by the end of April 2011 and bears interest at the rate of 6.99%. Additional senior debt of $31 million has been provided by a third party lender, Integrated Private Debt. APCo has a subordinated debt investment in the facility of $6.6 million and bears interest at the rate of 12.5%. APCo has the option to formally exchange its debt investment and fee interest in the project for a 75% equity interest, exercisable in February 2016.

In addition to interest payments on its debt financing, APUC is entitled to certain supervisory fees, estimated at $1.3 million in the first full year of operation. Total interest and fee payments in 2011 are estimated to be approximately $2.4 million representing approximately 75% of net cash flows from the facility.

i) Power Purchase Agreement

Red Lily I entered into a 25 year PPA with SaskPower dated as of July 30, 2008, which includes a 2% annual increase throughout the term of the agreement. On February 25, 2011, Red Lily I commenced commercial operation under the SaskPower PPA.
(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. To reduce the total tonnage of municipal waste being directed to landfills and to extend the useful life of existing landfills, considerable effort is being directed toward the establishment of energy-from-waste facilities. The establishment of energy-from-waste facilities is now a licensed process in certain states of the United States and Canadian provinces.

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”.

(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 majority of the EFW steam is diverted to the BCI Facility. See “BCI Facility” under “Material Facilities” for “Cogeneration”. 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) Power Purchase Agreement

The EFW Facility has entered into a PPA with OEFC which requires OEFC to purchase all the electricity produced by the facility. The OEFC uses the electricity to supply the grid in Ontario. The PPA expires in 2012. The Ontario Ministry of Energy has directed the OPA to enter into negotiations with APEFW to negotiate a new a new long term contract for the power output from the EFW Facility.

ii) Fuel Supply

Under a “tip or pay” waste supply agreement, Peel supplies the facility with a minimum of 127,900 tonnes per year of acceptable municipal solid waste. The agreement expires in 2012. Peel has the option to renew the agreement for an additional five-year term. The agreement requires Peel to pay a “tipping fee” for each tonne of acceptable waste delivered, plus an additional fee for each tonne of acceptable waste delivered above the base amount. Additional volumes of waste may be supplied by Peel at the request of either party, subject to the agreement of the other. The agreement provides that if certain taxes are imposed or revised standards are set for certain environmental or operating matters affecting the
facility, the tipping fees paid by Peel will be increased to reflect the increased capital or operating costs so imposed by the taxes or revised standards.

(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. 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 Sanger Facility is a combined cycle generating station comprised of a 44 MW General Electric LM6000 natural gas fired turbine, commissioned in 2008, and a 12.5 MW Westinghouse steam turbine, commissioned in 1991. The facility is owned by Algonquin Power Sanger LLC, a subsidiary of APFA.

i) Power Purchase Agreement

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, 2010. 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 Windsor Locks 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 Algonquin Power Windsor Locks LLC, an indirect subsidiary of APCo.
Prior to April 2010, the Windsor Locks Facility ran at capacity, providing the steam and power requirements of Ahlstrom pursuant to the Energy Services Agreement (“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.

In this regard, APCo has completed preliminary engineering and environmental permitting work for the installation of a more appropriately sized 14.2 MW combustion gas turbine. The total expected capital cost for this project is estimated at approximately U.S. $20 million. APCo believes it is eligible to receive a one-time non-recurring grant from the State of Connecticut equivalent to US $450/KW to a maximum of U.S. $6.6 million to 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 Windsor Locks of approximately U.S. $500,000/year. In addition to installing the new gas turbine, APCo would expect to continue to operate and maintain the existing equipment. APCo also believes that this project would qualify for a combined heat and power Investment Tax Credit (“ITC”) Grant program sponsored by the US Federal Government. The benefit of the ITC grant is approximately U.S. $1 million in addition to the Connecticut grant. APCo’s decision to make any investment in new capital for this site will be based on an assessment of the incremental earnings and certainty of such incremental earnings against such additional investment. With a repowered facility the existing combustion turbine would continue to be used as a capacity and reserve resources participating in the ISO-NE markets.

i) Energy Services Agreement and Ground Lease

The Windsor Locks 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 to the facility site to Algonquin Power Windsor Locks, LLC and utilizes thermal steam energy and a portion of electrical generation of the Windsor Locks Facility for use at its specialty fibers composites mill located adjacent to the Windsor Locks Facility. Both the ground lease and the ESA expire in January 2018, subject to certain early termination rights in favour of Ahlstrom and rights of renewal in favour of both parties. Payments under the ESA are fully indexed to the cost of natural gas consumed by the Facility.

ii) Power Purchase Agreement

The electrical output of the Windsor Locks Facility not used to meet Ahlstrom’s requirements is committed to the ISO-NE electricity market. Since April 2010, the Windsor Locks Facility has bid its remaining available capacity of approximately 40 MW into the thirty minute forward operating reserve market. APCo has entered into an agreement with Emera Energy Services Inc. to manage the off-take sales from this Facility into the ISO-NE market. See “Current Development Projects - Windsor Locks” under “Development” for further details.

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 and Yankee Gas continue to negotiate a new agreement that will allow Windsor Locks to use Yankee Gas as a local distribution company which will enhance the Windsor Locks Facility’s purchase options for its natural gas requirements.
(3) **BCI Facility**

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

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

(4) **Kirkland Facility**

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

APT owns 32.4% of the Class B non-voting shares issued by Kirkland. It is Kirkland’s policy to declare and pay quarterly dividends on its shares equal to substantially all of its after-tax income. Kirkland had a put option to sell the Kirkland 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 Cochrane Facility is owned by Cochrane Power Corporation (“Cochrane”) which burns natural gas and wood waste to generate power using a gas turbine and a steam turbine. The Cochrane Facility was commissioned in 1990 and is currently managed by Northland. Electricity produced by the Cochrane Facility is sold to OEFC pursuant to a 25 year contract, which expires in 2014. The majority of the natural gas used by the 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 Cochrane 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: Energy Services Business**

The primary business of the Energy Services Business is to market the output of the Tinker Facility which would otherwise sell the energy it generates on a merchant basis. The Energy Services Business 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**

The Energy Services Business involves standard offer contracts and direct customer contracts for the supply of energy to commercial and industrial customers. The Energy Services Business is based on a series of short-term energy supply agreements.

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

The Energy Services Business provides energy to commercial and industrial customers in the northern Maine and New Brunswick markets. The Energy Services Business 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 at an average rate of $86/MW-hr on an annualized basis.

The Energy Services Business 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 the Energy Services Business to service its customers and provides a natural hedge on supply costs of the Energy Services Business.

In addition to the energy generation provided by the Tinker Assets, the Energy Services Business purchases additional energy on the open market in order to service its customer demand. APCo manages the risk associated with this business through internally generated energy from the Tinker Assets, as well as through the purchase of fixed volume/prices from the ISO-NE market. In addition, APCO 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**

The Energy Services Business is based on 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.

The hydroelectric and thermal generation assets offer capacity to support the energy services obligations in northern Maine. The acquisition improves hydrologic diversification through a new geographical area to the APCo generation portfolio and builds APCo’s Eastern Canadian generating presence.

The Energy Services Business 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. Subsequent to December 31, 2010, the Energy Services Business 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 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. The Development division is led by six full time employees who have access to, and support from, all of APCo’s available resources to assist it in the development of projects. Typically, the division draws upon the support of the finance, engineering, technical services, and environmental and regulatory compliance groups. It also 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 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.

(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. In May 2009, 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 similar legislation. British Columbia has announced the Clean Energy Act and Nova Scotia is pursuing the 2010 Renewable Electricity Plan and will be establishing pricing for its ensuing Community FIT program in April of 2011. Both of these proposed pieces of legislation have set
aggressive targets for the development of new, renewable power production. They also introduce the concept of fixed pricing based on a FIT for some categories of new renewable power projects. 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 a significant number of U.S. states.

In the United States, the *New Energy for America Plan* supports 10% of the country’s electricity being generated from renewable sources by 2012 and 25% by 2025. The demand for additional renewable power is also expected to benefit from the desire by various government entities to increase infrastructure spending.

(iii) Current Development Projects

(1) **Amherst Island**

On February 25, 2011, APUC announced that the OPA has awarded a FIT contract to Windlectric, owner of the wholly-owned 75 MW Amherst Island Wind Project, located on Amherst Island in the village of Stella, approximately 25 kilometres southwest of Kingston, Ontario. The contract has been awarded as part of the second round of the OPA’s FIT program.

The project is currently contemplated to use more efficient Class III wind turbine generator technology and will be developed by APCo. While final turbine selection remains to be made, modelling the higher energy capture ratios of turbines, such as the Vestas V100 or Repower MM100, forecast that the available wind resource would produce approximately 247 GW hrs of power annually. Funding for the total capital costs currently estimated to be $220 million will be arranged and announced when all required permitting and all other pre-construction conditions have been satisfied. 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 months.

(2) **Quebec Community Wind Projects**

In July 2010, APCo and Société en Commandite Val-Eo, a cooperative with a development project located in the Lac Saint-Jean region of Quebec, and the community of Saint-Damase submitted separate proposals into Hydro-Québec’s 250 MW wind Request for Proposal. On December 20, 2010, both projects were awarded contracts that stipulate the use of ENERCON turbines.

(3) **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 currently envisioned to consist of twelve 2 MW ENERCON E-82 wind turbine generators, producing approximately 86,000 MW-hrs 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, with all major authorizations targeted for completion by the end of 2012.

(4) **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 3 MW ENERCON E-101 wind turbine generators, producing approximately 66,000 MW-hrs 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 municipality 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, with all major authorizations targeted for completion by the end of 2012.

(5) **Morse**

On March 21, 2011, APCo announced it has executed an asset purchase agreement with Kineticor to acquire the Morse Projects, assets related to two proposed adjacent 10 MW wind energy development projects in Saskatchewan.

The Morse Projects were selected by SaskPower for award of PPAs in accordance with the SaskPower Green Options Partners Program in May 2010. Upon SaskPower’s approval and execution of the PPAs, Kineticor will assign the PPAs to APCo. The Morse Projects are expected to be completed in late 2013.

The Morse Projects are to be constructed near Morse, Saskatchewan, approximately 180 km west of Regina and 400 km west of the 26.4 MW wind generation facility in southeastern Saskatchewan. It is contemplated that the Morse Projects will be situated on 1,120 acres of private lands, with additional land under lease or option in order to facilitate future expansion of the Morse Projects.

The total annual energy production for the Morse Projects is estimated to be 75,000 MW-hrs. While equipment selection and construction details remain to be finalized, the capital cost to construct the Morse Projects is currently estimated to be $55-$60 million, inclusive of acquisition costs. The first year PPA rate is set at $101.98 per MW-hr 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.

(6) **Red Lily II**

In addition to the now completed Red Lily I project, APCo has secured additional land options related to property around Red Lily I to facilitate a 106 MW expansion (“Red Lily II”). The viability of the expanded project will be conditional upon a review of the actual operating results from Red Lily I. During the first quarter of 2010, APCo responded to the request for quotations issued by SaskPower by submitting requested information pertaining to Red Lily II.

Successful development of wind projects is subject to significant risks and uncertainties including the ability to obtain financing on acceptable terms within deadlines imposed by the utility, reaching agreement with any other external parties involved in the project, currency fluctuations affecting the cost of major capital components such as wind turbines, price escalation for construction labour and other
construction inputs and construction risk that the project is built without mechanical defects and is completed on time and within budget estimates.

(7) Windsor Locks

The Windsor Locks Facility is a 54 MW natural gas power 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 the ESA.

The balance of the Windsor Locks Facility’s electrical generating capacity is sold to customers through the ISO-NE electrical market. The facility currently participates in the ISO-NE Forward Capacity Market and the day-ahead energy market. Assuming acceptable auction pricing is available in April 2011, the additional electrical capacity of approximately 26 MW at the Windsor Locks Facility will be made available into the summer 2011 Forward Reserve Market. In addition, APCo’s Energy Services Business will use the production from the Windsor Locks Facility to support retail industrial electrical sales in the ISO-NE market.

APCo has completed preliminary engineering and environmental permitting work for the installation of a 14.2 MW combustion gas turbine which is more appropriately sized to meet the electrical and steam requirements of Ahlstrom. The total expected capital cost for this project is estimated at approximately U.S. $20 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 to 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 $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. APCo also believes that this project would qualify for a combined heat and power 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. APCo’s decision to make any investment in new capital for this site will be based on an assessment of the incremental earnings against such additional investment.

During 2011, it is expected that APCo will continue to earn revenue from steam and electrical sales to Ahlstrom, steam and electrical capacity payments made by Ahlstrom, as well as energy and capacity payments through sales to ISO-NE. Under the expected ISO-NE operating protocol APCo will need to acquire approximately 0.9 million MMBTU of natural gas annually in addition to the amount of natural gas purchased to serve the needs of Ahlstrom (in respect of which APCo receives reimbursement from Ahlstrom under the ESA).

(8) 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.

APCo is currently collecting wind data on three sites in Saskatchewan and responded to Saskatchewan’s Request for Qualifications to procure up to 175 MW of wind power from one or more independent power producers. These sites have met the qualifications and APCo will likely submit project proposals into future RFPs.

Discussions with the OPA indicate that energy procurement initiatives have been positively influenced by the GEA. The GEA is intended to provide the catalyst for the development of 50,000 new green economy jobs and is viewed by APCo as positive for the development of renewable energy in Ontario. The Development division is maintaining relationships with potential partners for the development of a number of projects that could qualify under anticipated procurement initiatives undertaken by the OPA in accordance with the GEA.

APCo had previously submitted applications for approximately 120 MW of on-shore wind energy projects in eastern Ontario under the GEA’s FIT program. The on-shore wind price set by the FIT program is $0.135 per KWh. APCo has received confirmation from the OPA that the remaining 42 MW of applications submitted under the FIT program are now being reviewed under the Economic Connection Test.

APCo has applied to become applicant of record for three Crown land sites in Ontario under the Ministry of Natural Resources wind power site release program.

Each project being contemplated is subject to a significant level of due diligence and financial modeling to ensure it satisfies return and diversification objectives established for the Development division. Accordingly, the likelihood of proceeding with some or all of these projects depends on the outcome of due diligence, material contract negotiations, the structure of future calls for tender, and request for proposal programs. To maximize APCo’s opportunities for development, new renewable and high efficiency thermal energy generating facilities are being pursued utilizing a variety of technologies and in diverse geographic locations.

(v) Future Development Projects – Existing Facilities

(1) St. Leon II

APCo is exploring multiple options related to the St. Leon facility including pursuing a future adjacent project and/or pursuing an increase in the installed capacity of the existing facility. The projects being reviewed have a potential generation capacity of over 85 MW. In the event these projects are developed, it is currently estimated to require an investment of approximately $250 million.

(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 Water are located in Arizona, Texas and Missouri. Liberty Water’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 Water 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 Water Services business unit is attached in Schedule C.

(1) Arizona

The 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 of Liberty Water.

The treatment plant utilizes an extended aeration 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 three 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 Facility

The Litchfield Facility is a water distribution and wastewater treatment facility located in the West Valley of Maricopa County, 15 miles west of Phoenix, Arizona whose service area includes sections of the cities of Goodyear and Avondale. The Litchfield Facility is owned by a wholly-owned subsidiary of Liberty Water.

The Litchfield 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.

(iv) Credit Facility

The Litchfield 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, 2009 of U.S. $3.8 million bearing interest at the rate of 5.87%. The second series was issued in 2001 with a principal amount as of December 31, 2010 of U.S. $7.2 million and bearing interest at the rate of 6.71%. 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, 2010 was U.S. $1.1 million.

(1) 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 Water.

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

(2) Rate Cases - General

In 2010, Liberty Water 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 Water 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 15, 2011:

<table>
<thead>
<tr>
<th>Completed Rate Cases</th>
<th>Date of Rate Increases</th>
<th>Annual U.S. $ Revenue Increase Requested</th>
<th>Annual U.S. $ Revenue Increase Granted</th>
</tr>
</thead>
<tbody>
<tr>
<td>Arizona</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Black Mountain</td>
<td>October 2010</td>
<td>$1.0 million</td>
<td>$0.7 million</td>
</tr>
<tr>
<td>Litchfield</td>
<td>December 2010</td>
<td>$11.6 million</td>
<td>$7.1 million</td>
</tr>
<tr>
<td>Rio Rico</td>
<td>February 2011</td>
<td>$1.6 million</td>
<td>$0.9 million</td>
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<td>Texas</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Texas Utilities (Silverleaf – 4 utilities)</td>
<td>October 2009</td>
<td>$1.2 million</td>
<td>$1.2 million</td>
</tr>
<tr>
<td>Tall Timbers</td>
<td>July 2009</td>
<td>$0.2 million</td>
<td>$0.2 million</td>
</tr>
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</table>
In Arizona, the ACC requires a full regulatory process for all rate cases using a historic test year. On August 5, 2010, the Black Mountain Facility received a recommended order (“ROO”) recommending an annualized rate increase of approximately U.S. $0.7 million effective September 1, 2010. The Black Mountain Facility filed its rate case in December 2008 using a June 30, 2008 test year. The ROO was approved in entirety at the Commission’s open meeting held in August.

On October 5, 2010, Liberty Water received a ROO for the Litchfield 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 under terms to be determined during the second phase of the Litchfield rate case which will focus on amounts charged for hookup fees and the methodology for recovery of foregone revenues due to the phase in of the rate increase. This phase is expected to occur later in 2011. The Litchfield Facility filed its rate case in March 2009 using a September 2008 test year.


The Bella Vista, Northern Sunrise and Southern Sunrise Facilities filed rate cases in August 2009 using a March 31, 2009 test year. It is anticipated that the regulatory review of the proposed rates and tariffs for Bella Vista, Northern Sunrise, and Southern Sunrise Facilities will be completed in Q1 2011.

All of these facilities are located in Arizona.

In Texas, the TCEQ allows the utility’s customers a period of 90 days from the effective date of the proposed rates to object to the imposition of interim rates pending final rates determination. If greater than 10% of a specific Texas utility’s customers object to the new proposed rates, the proposed rates would be subjected to a full regulatory hearing process administered by the TCEQ in order to finalize the rates. If fewer than 10% of the customers record an objection to the proposed rates, those proposed rates are likely to be adopted and declared final as proposed. Any difference between the interim rates charged and collected and the final rates as approved by TCEQ will be subject to a retroactive adjustment and refund on the customers’ subsequent monthly bill.

Liberty Water entered into negotiated settlements with the customers of the Texas Silverleaf and Tall Timbers Facilities, resulting in the achievement of the full estimated annualized revenue increase of $1.2 million and $0.2 million, respectively. The Woodmark Facility did not receive objections from 10% of the customer base and also achieved the full estimated annualized revenue increase of $0.1 million. The five
Texas Facilities filed rate cases in April 2009, and Woodmark in Texas filed in July 2009, all with test years ended December 31, 2008.

(h) 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 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 Energy’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 Energy 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 Energy 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 Energy’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 48,000 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 Energy.

Calpeco’s most recent rate case was settled in 2009. It is anticipated that the next Calpeco rate case will be filed in June 2011 for the prospective years of 2012-2014.

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) 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 including the new California Particulate Matter emission requirements and NOx emissions limits. 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.
iii)  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.

iv)  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.

v)  Power Purchase Agreement

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.

vi)  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 2010 and 2009

As at March 31, 2011, APUC owned, directly or indirectly, debt, equity and royalty and other interests in 59 power generation facilities including those identified in “Other Interests in Energy Related Developments”, one electrical distribution facility and 19 water distribution and wastewater facilities. For the year ended December 31, 2010, APUC derived approximately 74.4% of its revenues from its interests in power generation facilities (71.7% in 2009), 4.9% of its revenues from waste disposal fees (7.7% in 2009) and 20.7% of its revenues from its interests in water distribution and wastewater facilities (20.6% in 2009).

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.

The Energy Services Business 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 Energy Services Business.

The electrical distribution service business of Liberty Energy requires specialized knowledge of electrical utility distribution systems and its various components. Liberty Energy has contracted the services of 41 employees that previously operated and maintained Calpco’s electrical distribution network. In addition Calpco has also recruited qualified individuals from within APCo and Liberty Water that have experienced operating regulated utilities and electrical generation facilities.

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.

APCo 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.

APCo 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. APCo will continue 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 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, 2010. 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. APCo has assessed the likelihood of these risks becoming a contingent environmental liability as remote; therefore APCo 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 7 full time
equivalent positions based out of head office and have an annual budget of approximately $1.0 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 79 employees who are involved in the operation of the renewable energy facilities, 17 employees who provide technical, environmental and safety services to APUC, an additional 52 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 45 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 Water and Liberty Energy currently has 6 employees. In addition, Liberty Water currently has 124 employees. Liberty Energy currently employs approximately 50 employees. With the exception of 41 employees at the California Utility, the employees of Liberty Utilities employees are non-unionized.

3.8 Foreign Operations

For 2010, 59% of the gross revenue of APUC was generated in the United States. As at March 31, 2011, APUC has interests in 50 facilities located in the United States, including 19 water distribution and wastewater treatment facilities.

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 Intangible Properties

The “Algonquin” name and trademark and related marks and designs are licenced to APUC by APC under a non-exclusive, royalty-free trademark licence agreement dated December 23, 1997 between APC and APUC. APUC, by using the “Algonquin” name, has the benefit of the goodwill and recognition associated with APC and its affiliates’ use of the “Algonquin” name in the energy sector for the past thirteen years.

The trademark “Liberty Water” and the water drop logo for Liberty Water has been registered as a trademark and as a service mark to Liberty Water Co. The trademark and water drop logo have been licensed to the subsidiaries of Liberty Water Co. Also, as discussed in “Liberty Water Chain” above, these subsidiaries have trade name, business name or “doing business as” registrations that allow them to conduct business under the name “Liberty Water”. These registrations are significant to the brand name recognition of the APUC Business that is Liberty Water.
APUC is in the process of taking out additional intellectual property right protection for the other marks and names used in the conduct of the APUC Businesses.

3.10 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.

(a) 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.

(b) 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.

For the Energy Services Business, 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 Algonquin Energy Services is located in a “winter peaking” region.

(c) Water Utilities

For Liberty Water, demand for water is affected by weather conditions and temperature. Demand for water during warmer months is generally greater than cooler months due to requirements for irrigation, swimming pools, cooling systems and other outside water use. If there is above normal rainfall or rainfall is more frequent than normal the demand for water may decrease adversely affecting revenues. Water distribution facilities depend on an adequate supply of water to meet present and future demands of customers. Drought conditions could interfere with sources of water supply used by the utilities and affect their ability to supply water in sufficient quantities to existing and future customers. An interruption in the water supply could have an adverse effect on the results of operations of the utilities. Government restrictions on water usage during drought conditions could also result in decreased demand for water, even if supplies are adequate, which could adversely affect revenues and earnings.

(d) Electric Utilities

For Liberty Electric, 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 Electric 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.
3.11 Customers

The APUC Businesses derive their revenues principally from the sale of electricity to large utilities. For the twelve months ended December 31, 2010, APUC Businesses’ revenues were derived as follows: Manitoba Hydro - approximately 10.8%; Hydro-Québec - approximately 11.2%; PG&E – approximately 8.6%; water distribution and wastewater treatment facilities – approximately 21%; waste disposal fees – approximately 5% and others - approximately 35%.

3.12 Economic Dependence

The largest customer on a percentage basis is Hydro-Québec which totalled 11.2% of gross revenues in the year ended December 31, 2010. This customer maintains an A+ S&P rating and receivables are invoiced monthly and generally collected within 30 days.

Similarly, the second largest customer on a percentage basis is Manitoba Hydro which totalled 10.8% of gross revenues in the year ended December 31, 2010. This customer maintains an AA S&P rating and receivables are invoiced monthly and generally collected within 20 days.

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

3.13 Social or Environmental Policies

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. 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 Water and Liberty Energy 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 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 45% of EBITDA and 60% 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 $15.5 million and increased reported expenses from U.S. operations of approximately $11.5 million or a net impact of $4.0 million ($0.038 per Common Share) on an annual basis.

This risk has historically been managed through the use of forward contracts as it required U.S. dollar cash inflows to meet Canadian dollar cash outflows. In 2009, APUC has determined that the practice of hedging 100% of its U.S. currency exposure was no longer appropriate and has unwound its existing forward currency contract program. As at March 15, 2011, APUC had no remaining forward currency hedges. APUC’s policy is not to utilize derivative financial instruments for trading or speculative purposes.

APUC took steps in the year ended December 31, 2010 to enter into long term debt facilities denominated in U.S. funds to create natural hedges against its U.S. operations.

(b) 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.

(c) Credit/Counterparty risk

APUC and its subsidiaries are subject to credit risk through its trade receivables. APUC does not believe this risk to be significant as approximately 72% of APCo Renewable Energy division’s revenue, approximately 70% of APCo Thermal Energy division’s revenue, and over 56% of APUC’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:

<table>
<thead>
<tr>
<th>Counterparty</th>
<th>Credit Rating *</th>
<th>Approximate Annual Revenues</th>
<th>Percent of Divisional Revenue</th>
</tr>
</thead>
<tbody>
<tr>
<td>Renewable Energy Division</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydro – Quebec</td>
<td>A+</td>
<td>20,500</td>
<td>25%</td>
</tr>
<tr>
<td>Manitoba Hydro</td>
<td>AA</td>
<td>19,700</td>
<td>24%</td>
</tr>
<tr>
<td>Ontario Electricity Financial Corporation</td>
<td>A+</td>
<td>8,400</td>
<td>10%</td>
</tr>
<tr>
<td>Counterparty</td>
<td>Credit Rating</td>
<td>Approximate Annual Revenues</td>
<td>Percent of Divisional Revenue</td>
</tr>
<tr>
<td>--------------------------------------------------</td>
<td>---------------</td>
<td>-----------------------------</td>
<td>------------------------------</td>
</tr>
<tr>
<td>Maine Public Service</td>
<td></td>
<td>4,600</td>
<td>6%</td>
</tr>
<tr>
<td>National Grid</td>
<td>A-</td>
<td>3,100</td>
<td>4%</td>
</tr>
<tr>
<td>Public Service Company of New Hampshire</td>
<td>BBB</td>
<td>2,800</td>
<td>3%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td><strong>$ 59,100</strong></td>
<td><strong>72%</strong></td>
</tr>
<tr>
<td><strong>Thermal Energy Division</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pacific Gas and Electric Company</td>
<td>BBB+</td>
<td>15,700</td>
<td>25%</td>
</tr>
<tr>
<td>Regional Municipality of Peel</td>
<td>AAA</td>
<td>14,500</td>
<td>23%</td>
</tr>
<tr>
<td>Ahlstrom</td>
<td>1R3</td>
<td>11,400</td>
<td>18%</td>
</tr>
<tr>
<td>Connecticut Light and Power Company</td>
<td>BBB</td>
<td>5,800</td>
<td>9%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td><strong>$ 47,400</strong></td>
<td><strong>70%</strong></td>
</tr>
</tbody>
</table>

* Ratings by Dunn & Bradstreet or Standard & Poor’s as of February 2011

The remaining revenue is primarily earned by Liberty Water. In this regard, the credit risk related to Liberty Water accounts receivable balances of U.S. $5.0 million is spread over approximately 70,000 customers, resulting in an average outstanding balance of approximately $72.00 per customer. Liberty Water has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers.

Liberty Energy’s customer base is primarily residential with exposure to large commercial accounts limited to below 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.

(d) Interest rate risk

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

(i) Power Generation

APCo’s project debt at the Long Sault Rapids and Chuteford Facilities are subject to a fixed rate of interest and thus are not subject to interest rate risk.

The Senior Credit Facility had a balance of $64.5 million as at December 31, 2010. Assuming the current level of borrowings over an annual basis, a 1% change in the variable rate charged would impact interest expense by $0.6 million annually. The fixed for floating interest rate swaps in an amount of $100.0 million which reduces volatility in the interest expense expired on December 31, 2010. At December 31, 2010, the mark to market value of the interest rate swap was a nil (December 31, 2009 – net $3.3 million liability).

Project debt at the St. Leon Facility had a balance of $68.8 million as at December 31, 2010. Assuming the current level of borrowings over an annual basis, a 1% change in the variable rate charged would impact interest expense by $0.7 million annually. Although the underlying debt with the project lenders carries variable rate of interest tied to the Canadian bank’s prime rate, APCo has entered into a fixed for floating interest rate swap on this project specific debt until September 2015 which mirrors the underlying debt’s interest and principal repayment schedule. This minimizes volatility in the interest expense on this
debt. The financial impact of interest rate changes are effectively offset between the change in interest expense and the change in value of the interest rate swap. APCo has effectively fixed its interest expense on its senior debt facility at 5.47%. At December 31, 2010, the mark-to-market value of the interest rate swap was a net liability of $5.4 million (2009 – net liability of $5.0 million).

Project debt at the Sanger Facility has a balance of U.S. $19.2 million as at December 31, 2010. Assuming the current level of borrowings over an annual basis, a 1% change in the variable rate charged would impact interest expense by $0.2 million annually.

(ii) Water Utilities

Liberty Water’s project debt at the Litchfield and Bella Vista Facilities are subject to a fixed rate of interest and thus is not subject to interest rate risk.

On December 22, 2010 Liberty Water entered into a U.S. $50 million private placement debt financing. The notes are senior unsecured with a 10 year term bearing a fixed rate of interest at 5.6%. The notes are interest only until June 2016 when annual principal repayments of U.S. $5.0 million annually commence. As Liberty Water’s senior notes are subject to a fixed rate of interest, they are not subject to interest rate risk. The proceeds of these notes was used to reduce short term borrowings on the Senior Credit Facility.

(iii) Electrical Utilities

On December 29, 2010, Liberty Energy entered into a U.S. $70 million senior unsecured private debt placement at the California Utility. The private placement is 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 and U.S. $25 million of 5.59% fifteen year notes. The proceeds of these notes was used to the partially fund the acquisition of the California Utility.

As Liberty Energy’s senior notes are subject to a fixed rate of interest, they are not subject to interest rate risk.

(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. 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.

During the year ended December 31, 2010, APUC paid a dividend of $0.24 per Common Share per year. On March 3, 2011, the Board approved an annual dividend increase of $0.02 per Common Share for a total annual dividend of $0.26, paid quarterly at a rate of $0.065 per Common Share. Based on the level of dividends paid during the twelve months ended December 31, 2010, cash provided by operating activities exceeded dividends declared by 2.0 times.

Subsequent to the year end, APCo concluded negotiations with its bank syndicate on the renewal of the Senior Credit Facility for a three year term with a maturity date of February 14, 2014. APCo reduced the total borrowing capacity of the Senior Credit Facility as part of its capital structure initiatives to term out some of the short-term borrowings under the Senior Credit Facility. Under the terms of the new banking agreement, as at December 31, 2010, APCo had $44.4 million of committed and available bank facilities remaining and $5.1 million of cash resulting in $49.5 million of total liquidity and capital reserves.
The U.S. $50 million debt financing entered into by Liberty Water on December 22, 2010 was used to reduce outstanding borrowings on the Senior Credit Facility. APUC is looking to reduce its level of short term borrowings under the Senior Credit Facility by way of obtaining long term debt at APCo through refinancing certain project specific financings or additional medium to long-term notes.

Credit facilities and project specific debt total approximately $257.4 million. In the event that APUC was required to replace the Senior Credit Facility and project debt with borrowings having less favourable terms or higher interest rates, the level of cash generated for dividends and reinvestment into the company 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.

(f) Commodity price risk

APCo’s exposure to commodity prices is primarily limited to exposure to natural gas price risk. Liberty Energy is exposed to energy purchase 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:

The 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 expenses of approximately $1.0 million on an annual basis. However, because the facility’s energy price is linked to the price of natural gas, this increase would result in a corresponding increase in revenue of $1.2 million or a net increase in operating profits of approximately $0.2 million.

The 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 expenses of approximately $1.0 million on an annual basis. However, historically, changes in the price of natural gas are generally matched with changes in market electricity prices which should result in a minimal impact on operating profit.

The 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 expenses of approximately $0.1 million on an annual basis. However, because the facility’s energy price is linked to the price of natural gas, this increase would result in a corresponding increase in revenue of $0.2 million or a net increase in operating profits of approximately $0.1 million.

The Energy Services Business provides the 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 2011. In the event that the Energy Services Business 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 though the use of short-term financial energy hedge contracts. Subsequent to December 31, 2010, APCo entered into a financial energy hedge contract to acquire approximately 215,000 MW-hrs of energy over a three year period starting March 1, 2011 at an average rate of approximately $50 per MW-hr.

The California Utility provides electric service to the Lake Tahoe basin and surrounding areas at rates approved by the CPUC. Calpeco 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. $5.4 million on an annualized basis.

This risk is mitigated though ECAC, 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 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.

(g) Risk of Default under Senior Credit Facility

As security for repayment of the Senior Credit Facility, APCo has, among other things, pledged the shares and other equity interests of certain of its subsidiaries. In addition to the amount outstanding under the Senior Credit Facility as described above, APCo has posted certain letters of credit totaling $33.1 million as security for obligations of the APCo businesses. The terms of the Senior Credit 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 Senior Credit Facility goes into default, or is not renewed or refinanced when due, there is a risk that the lenders could exercise their security.

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 dependant 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.

The water distribution networks of the Liberty Water 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.

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

These risks are mitigated through the diversification of APUC’s operations, both operationally (APCo, Liberty Water and Liberty Energy) 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.

(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.

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 expires in 2012 with two five year options to extend. 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 Water’s facilities are operated with the assumption that their services will be required in perpetuity and there are no contractual decommissioning requirements. In order to remain in compliance with the applicable regulatory bodies, Liberty Water 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 Water is allowed to earn a return on its investment.

Liberty Energy’s facilities are operated with the assumption that their services will be required in perpetuity and there are no contractual decommissioning requirements. In order to remain in compliance with the applicable regulatory bodies, Liberty Energy 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 Energy is allowed to earn a return on its investment.

(c) Environmental Risks

(i) Power Generation

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.

(ii) Water Utilities

Liberty Water 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 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 Water 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 Water 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.

(iii) Electrical Utilities

Liberty Energy 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 Energy 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 Energy 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.

(iv) Specific Environmental Risks

(1) Greenhouse Gas Initiatives

Several north-eastern U.S. States have formed a coordination group to develop a multi-state greenhouse gas mitigation action plan. This group, the Regional Greenhouse Gas Initiative ("RGGI"), has received backing from states where APCo operates facilities including Connecticut. RGGI drafted a model cap and trade legislation that has been endorsed by all of the states involved in the initiative. The cap and trade program will be implemented to regulate CO₂ emissions from large electrical generation facilities, including the Windsor Locks Facility. The RGGI regulation to implement a greenhouse gas cap and trade program was passed in Connecticut in late August 2008.

The Windsor Locks Facility is the only APCo site that is currently affected by the RGGI regulations. As such APCo will be required to purchase approximately 250,000 tons of CO₂ allowances per year, equivalent to the total annual CO₂ 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 2010, 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 working since 2009. The first compliance period is from January 2009 to December 2011. The Windsor Locks Facility produced 221,522 tons of CO₂ in 2009 and 189,124 tons in 2010. The Facility was allocated amounts under the Useful Thermal Set-Aside Energy Account ("UTSA") (approximately 50,000 tons of CO₂ per year) in both years. The Facility purchased additional allowances at $2.00/ton through the PPA agreement and at auctions. The Windsor Locks Facility purchased allowances for $357 in 2009 and $163 in 2010. For 2011, it is estimated that the Facility will produce 205,000 tons of CO₂, obtain allowances of 55,000 tons through the UTSA, and be required to purchase an additional 95,000 tons to comply with RGGI by the end of December. The Windsor Locks Facility purchased $189 of allowances at the auction of March 9, 2011 and anticipates purchasing approximately another $180 by December, assuming the current average price of $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. This group recently released details of its Regional Cap-and-Trade Program, which is scheduled to start on January 1, 2012. 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. As this process has just begun, it is too early to determine the potential financial impact on APCo and means available to mitigate this financial impact, if any.

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 and 2009. The inventory is presently being done for 2010. 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.

(2) Renewable Energy Division

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.

(3) Water Utilities

Liberty Water owns and operates the Litchfield Facility 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 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 Facility. EPA’s monitoring and control efforts have not indicated that the concentrations are being reduced or fully captured. Additional remedial efforts by the EPA to stop advancement and reduce TCE concentrations are underway. In the event that any wells exceed 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 Facility’s customers. In addition, the Litchfield 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, volume of water available at the new site, and acquisition of land and groundwater rights. Liberty Water does not believe it is exposed to a material liability and has not recorded a contingent environmental liability on its financial statements.
APUC’s policy is to record estimates of environmental liabilities when they are known or considered probable and the related liability is estimable. There are no known material environmental liabilities as at December 31, 2010.

(v)    Regimes that Could Impact APUC

(1)    Power Generation

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”.

(2)    Electrical Utilities

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.

(vi)   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.

(d)    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.

As discussed below under “Legal Proceedings”, APCo and APC 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 in 1996 in Québec Superior Court and claimed $5.4 million for amounts 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 but the decision has not been rendered. If the Québec AG is successful in final appeal on the Côte Ste-Catherine case, an adjustment and/or increase of the amount of dues payable under the water lease is possible.

(e) 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.

(f) 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.

(g) Obligations to Serve

Liberty Water’s and Liberty Energy’s 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 Water and Liberty Energy may be required to solicit additional capital or obtain additional borrowings to finance these future construction obligations.

4.3 Regulatory Climate and Permitting Risks

(a) Power Generation

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. 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.

(b) Water Utilities

Liberty Water’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 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 Water, and while Liberty Water 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 Water regularly works with these authorities to manage the affairs of the business.

(c) Electrical Utilities

Liberty Energy’s facility is 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 Energy, and while Liberty Energy 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 Energy regularly works with these authorities to manage the affairs of the business.

4.4 Dependence upon APUC Businesses

APUC is entirely dependent upon the operations and assets of APUC Businesses. 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 or distributions.

(a) Power Generation

The profitability of APCo’s Businesses may be affected by expiry of the present long-term PPAs to which certain of APCo’s Businesses are a party.
(b) Water Utilities

US 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.

Water 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 Water, and while Liberty Water 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.

(c) Electrical Utilities

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.

Electricity distribution 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 Energy, and while Liberty Energy 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.

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.

(a) Power Generation

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 2008 for a term of 3 years, until April 2011. The Tinker Facility is unionized and a new collective bargaining agreement was renegotiated in January 2011 for a term of 5 years.
(b) **Liberty Water**

All employees of Liberty Water and their material subcontractors are non-unionized.

(c) **Liberty Energy**

All employees of Liberty Energy are non-unionized with the exception of 41 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 3 years, until August 2013.

4.7 **Dependence Upon Key Customers**

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, distributable cash available to Shareholders would decline.

4.8 **Potential Conflicts of Interest**

As discussed in “Developments in Fiscal 2009” in “Three Year History” above, agreement was reached on December 21, 2009 to internalize management. Unit holders had previously been dependent on APMI for the administration of the Fund 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 Officers of APUC in relation to the interests of APUC. Transactions involving related parties, including the Senior Officers 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, 2010.

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.

5. **DIVIDENDS/DISTRIBUTIONS**

The total amount of dividends/distributions declared for fiscal 2008, 2009 and 2010 were $57.8, $19.3 and $22.8 million, respectively. The amount of dividends/distributions declared for each Trust Unit or Common Share of the Fund for fiscal 2008, 2009 and 2010 were $0.75, $0.24 and $0.24, respectively.
Since January 1, 2010, APUC follows a quarterly dividend schedule, subject to subsequent Board declarations each quarter. Effective March 3, 2011, the Board established a quarterly dividend of $0.065 or $0.26 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”.

6. DESCRIPTION OF CAPITAL STRUCTURE

6.1 Common Shares

APUC is authorized to issue an unlimited number of Common Shares. The holders of Common Shares are entitled to one vote per Common Share at meetings of the shareholders of the Corporation and upon liquidation, dissolution or winding up of APUC to receive pro rata the remaining property and assets of APUC.

As at December 31, 2010, APUC had 95,422,778 issued and outstanding Common Shares on a fully diluted basis. On January 1, 2011, following Emera’s exercise of its subscription receipts, APUC had 103,945,778 issued and outstanding Common Shares on a fully diluted basis. The Common Shares issued to Emera were in connection with APUC’s partnership with Emera entered into on April 23, 2009 wherein APUC agreed to issue approximately 8.5 million Common Shares of APUC at a price of $3.25 per Common Share to finance a portion of the acquisition of the California Utility. As at March 15, 2011, APUC had 103,988,335 issued and outstanding Common Shares on a fully diluted basis. Subsequent to December 31, 2010, Series 1A Debentures valued at approximately $72 were converted to 17,558 Common Shares and Series 3 Debentures values at approximately $105 million were exchanged for 24,999 Common Shares.

6.2 Preferred Shares

APUC is authorized to issue an unlimited number of preferred shares, issuable in series. There are no preferred shares issued or outstanding.

6.3 Convertible Debentures

APUC currently has outstanding three series of convertible debentures:

- a principal amount of $62,398 pursuant to 7.50% convertible unsecured subordinated debentures due November 33, 2014 at a price of $1,000 per debenture (the “Series 1A Debentures”);
- a principal amount of $59,967 pursuant to 6.35% convertible unsecured subordinated debentures due November 30, 2016 at a price of $1,000 per debenture (the “Series 2A Debentures”); and
- a principal amount of $62,800 pursuant to 7.00% convertible unsecured subordinated debentures due June 30, 2017 at a price of $1,000 per debenture (the “Series 3 Debentures”).

If all of the principal amount of the Series 1A Debentures, the Series 2A Debentures and the Series 3 Debentures (the “APUC Debentures”) were converted by the holders thereof, an additional 40,830,923 Common Shares will be issued pursuant to the terms of the trust indenture (the “Trust Indenture”) dated
as of October 27, 2009 between the APUC and CIBC Mellon Trust Company (the “Debenture Trustee”) with respect to the Series 1A Debentures and the Series 2A Debentures and 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

In July 2004, the Fund issued 85,000 convertible unsecured debentures at a price of $1,000 for each debenture maturing on July 31, 2011 (“Series 1 Debentures”). On October 27, 2009, there were 84,964 convertible debentures outstanding with a face value of $84,964. On October 27, 2009, $63,755 of the outstanding Series 1 Debentures was exchanged for the Series 1A Debentures in a principal amount of $66,943. The remaining Series 1 Debentures having a face value of $21,209, not converted to Series 1A Debentures were exchanged for 6,607,027 Common Shares.

The Series 1A Debentures pay interest semi-annually in arrears on January 1 and July 1 each year. As at March 15, 2011, there were 62,398 Series 1A Debentures outstanding with a face value of $62,398.

(b) Series 2A Debentures

In November 2006, the Fund issued 60,000 convertible unsecured debentures at a price of $1,000 for each debenture maturing on November 30, 2016 (“Series 2 Debentures”). On October 27, 2009, there were 59,967 Series 2 Debentures outstanding with a face value of $59,967. On October 27, 2009, all of the outstanding Series 2 Debentures were exchanged for Series 2A Debentures in a principal amount of $59,967.

The Series 2A Debentures pay interest semi-annually in arrears on April 1 and October 1 each year. As at March 15, 2011, there were 59,967 Series 2A Debentures outstanding with a face value of $59,967.

(c) Series 3 Debentures

On December 2, 2009, APUC issued 63,250 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, 2011, there were 62,800 Series 3 Debentures outstanding with a face value of $62,800.

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 1A 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 November 30, 2014 (the “Series 1A Maturity Date”) and the business day immediately preceding the date specified by APUC for redemption of the Series 1A Debentures, at a conversion price of $4.08 per Common Share (the “Series 1A Conversion Price”), being a ratio of approximately 245.1 Common Shares per $1,000 principal amount of Series 1A Debentures. The Series 1A Debentures bear interest from the date of issue at 7.50% per annum, which will be payable semi-annually on July 1 and January 1 in each year, which commenced on January 1, 2010 (each, a “Series 1A Interest Payment Date”).

The Series 2A 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 November 30,
2016 (the “Series 2A Maturity Date”) and the business day immediately preceding the date specified by APUC for redemption of the Series 2A Debentures, at a conversion price of $6.00 per Common Share (the “Series 2A Conversion Price”) being a ratio of approximately 166.7 Common Shares per $1,000 principal amount of Series 2A Debentures. The Series 2A Debentures bear interest from the date of issue at 6.35% per annum, which will be payable semi-annually on April 1 and October 1 in each year, commencing on April 1, 2010 (each, a “Series 2A Interest Payment Date”).

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: (a) the latest Series 1A Interest Payment Date (in the case of the Series 1A Debentures) or (b) the latest Series 2A Interest Payment Date (in the case of the Series 2A Debentures). Notwithstanding the foregoing: (a) no Series 1A Debentures may be converted on any Series 1A Interest Payment Date and during the five business days preceding January 1 and July 1 in each year; (b) no Series 2A Debentures may be converted on any Series 2A Interest Payment Date and during the five business days preceding April 1 and October 1 in each year; and (c) 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 Trust Indenture and the Series 3 Trust Indenture provide for the adjustment of the Series 1A Conversion Price, the Series 2A Conversion Price and 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 1A Conversion Price, the Series 2A Conversion Price or 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 in either the Series 1A Conversion Price, the Series 2A
Conversion Price or the Series 3 Conversion Price, unless the cumulative effect of such adjustments
would change the Series 1A Conversion Price, the Series 2A Conversion Price or 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

During the period from January 2, 2011 to January 1, 2012, the Series 1A 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 1A Conversion Price.

On or after January 1, 2012 and prior to the Series 1A Maturity Date, the Series 1A 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.

During the period from January 2, 2011 to January 1, 2012, the Series 2A 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 2A Conversion Price.

On or after January 1, 2012 and prior to the Series 2A Maturity Date, the Series 2A 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.

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 1A Maturity Date, the Series 2A Maturity Date or 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 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 Trust Indenture as all indebtedness of APUC, other than the APUC Debentures and any other debentures issued under the Trust Debenture, (whether outstanding as at the date of the 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 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 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 Trust Indenture contains notification provisions to the effect that:

(a) 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

(b) 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.

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 Trust Indenture may be modified in accordance with the terms of the 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 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 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 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 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 Shareholders’ Rights Plan

The Rights Plan is designed to ensure the fair treatment of shareholders in any transaction involving a potential change of control of APUC and will provide the board of directors of the Corporation and shareholders with adequate time to evaluate any unsolicited take-over bid and, if appropriate, to seek out alternatives to maximize shareholder value. The Rights Plan was approved by shareholders at the Meeting until the termination of the annual general meeting of the Shareholders of APUC in 2013 or its termination under the terms of the Rights Plan. The Rights Plan is similar to rights plans adopted by many other Canadian corporations. Until the occurrence of certain specific events, the rights will trade with the Common Shares of APUC and be represented by certificates representing the Common Shares. The rights become exercisable only when a person, including any party related to it or acting jointly with it, 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.

7. MARKET FOR SECURITIES

7.1 Trading Price and Volume

(a) Common Shares

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).

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<thead>
<tr>
<th></th>
<th>High ($)</th>
<th>Low ($)</th>
<th>Volume (000's)</th>
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<tbody>
<tr>
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<td>4.44</td>
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<td>March</td>
<td>4.80</td>
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<table>
<thead>
<tr>
<th>2010</th>
<th>High ($)</th>
<th>Low ($)</th>
<th>Volume (000's)</th>
</tr>
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<tr>
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<td>4.53</td>
<td>4.23</td>
<td>4,304,658</td>
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<tr>
<td>May</td>
<td>4.45</td>
<td>3.50</td>
<td>7,164,537</td>
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<td>June</td>
<td>4.22</td>
<td>3.93</td>
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<td>4.32</td>
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<td>August</td>
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<td>September</td>
<td>4.75</td>
<td>4.21</td>
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<td>November</td>
<td>5.04</td>
<td>4.61</td>
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<td>December</td>
<td>5.10</td>
<td>4.64</td>
<td>5,076,401</td>
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(b) Series 1A Debentures

Series 1A Debentures are listed and posted for trading on the TSX under the symbol “AQN.DB”. 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).

<table>
<thead>
<tr>
<th>2010</th>
<th>High ($)</th>
<th>Low ($)</th>
<th>Volume (000's)</th>
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<tr>
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<td>112.00</td>
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<td>117.99</td>
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<td>115.00</td>
<td>109.01</td>
<td>13,889</td>
</tr>
<tr>
<td>May</td>
<td>110.01</td>
<td>102.50</td>
<td>10,793</td>
</tr>
<tr>
<td>June</td>
<td>108.65</td>
<td>104.50</td>
<td>22,366</td>
</tr>
<tr>
<td>July</td>
<td>110.90</td>
<td>107.71</td>
<td>34,053</td>
</tr>
<tr>
<td>August</td>
<td>109.01</td>
<td>106.76</td>
<td>3,165</td>
</tr>
<tr>
<td>September</td>
<td>116.00</td>
<td>109.10</td>
<td>22,342</td>
</tr>
<tr>
<td>October</td>
<td>123.02</td>
<td>114.09</td>
<td>51,254</td>
</tr>
<tr>
<td>November</td>
<td>124.04</td>
<td>114.53</td>
<td>67,152</td>
</tr>
<tr>
<td>December</td>
<td>124.75</td>
<td>116.44</td>
<td>30,933</td>
</tr>
</tbody>
</table>

(c) Series 2A Debentures

Series 2A Debentures are listed and posted for trading on the TSX under the symbol “AQN.DB.A”. 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).

<table>
<thead>
<tr>
<th>2010</th>
<th>High ($)</th>
<th>Low ($)</th>
<th>Volume (000's)</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
<td>105.00</td>
<td>101.00</td>
<td>4,810</td>
</tr>
<tr>
<td>February</td>
<td>104.50</td>
<td>101.00</td>
<td>5,560</td>
</tr>
<tr>
<td>March</td>
<td>108.00</td>
<td>101.25</td>
<td>8,520</td>
</tr>
<tr>
<td>April</td>
<td>105.00</td>
<td>102.75</td>
<td>4,230</td>
</tr>
<tr>
<td>May</td>
<td>104.00</td>
<td>95.01</td>
<td>4,170</td>
</tr>
<tr>
<td>June</td>
<td>104.90</td>
<td>100.00</td>
<td>2,650</td>
</tr>
<tr>
<td>July</td>
<td>104.90</td>
<td>101.60</td>
<td>4,290</td>
</tr>
<tr>
<td>August</td>
<td>105.00</td>
<td>102.01</td>
<td>7,380</td>
</tr>
<tr>
<td>September</td>
<td>106.75</td>
<td>104.25</td>
<td>3,080</td>
</tr>
<tr>
<td>October</td>
<td>108.00</td>
<td>105.00</td>
<td>3,560</td>
</tr>
</tbody>
</table>
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).

<table>
<thead>
<tr>
<th>2010</th>
<th>High ($ )</th>
<th>Low  ($ )</th>
<th>Volume (000's)</th>
</tr>
</thead>
<tbody>
<tr>
<td>November</td>
<td>107.85</td>
<td>104.10</td>
<td>4,400</td>
</tr>
<tr>
<td>December</td>
<td>106.50</td>
<td>103.50</td>
<td>3,230</td>
</tr>
</tbody>
</table>

7.2 Prior Sales

On August 12, 2010, a total of 1,102,041 stock options, being the only unlisted securities of the Corporation that were issued, were granted to certain executive officers of APUC as set forth below. On March 22, 2011 an additional 892,107 stock options were granted to certain executive officers of APUC as set forth below.

<table>
<thead>
<tr>
<th>Date of Grant</th>
<th>Number of Stock Options</th>
<th>Exercise Price</th>
<th>Term</th>
</tr>
</thead>
<tbody>
<tr>
<td>August 12, 2010,</td>
<td>1,102,041</td>
<td>$4.05</td>
<td>8 years</td>
</tr>
<tr>
<td>March 12, 2011</td>
<td>892,107</td>
<td>$5.23</td>
<td>8 years</td>
</tr>
</tbody>
</table>

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 the Fund. Unless otherwise indicated, the individuals have been in their principal occupations for more than five years.
<table>
<thead>
<tr>
<th>Name and Place of Residence</th>
<th>Principal Occupation</th>
<th>Served as Director or Officer of APUC from</th>
<th>Number of Common Shares</th>
</tr>
</thead>
<tbody>
<tr>
<td>CHRISTOPHER J. BALL Toronto, Ontario, Canada Age: 60</td>
<td>Mr. Ball is currently the Executive Vice President of Corfinance 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.</td>
<td>Director of APUC since October 27, 2009. Trustee of the Fund since October 22, 2002</td>
<td>24,200</td>
</tr>
<tr>
<td>KENNETH MOORE Toronto, Ontario, Canada Age: 52</td>
<td>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 &amp; 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 Ch. Dir. (Chartered Director).</td>
<td>Director of APUC since October 27, 2009. Trustee of the Fund since December 18, 1998</td>
<td>18,000</td>
</tr>
<tr>
<td>GEORGE L. STEEVES Aurora, Ontario, Canada Age: 61</td>
<td>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 the Fund, 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.</td>
<td>Director of APUC since October 27, 2009. Trustee of the Fund since September 8, 1997</td>
<td>17,241(^{1})</td>
</tr>
<tr>
<td>CHRISTOPHER HUSKILSON Wellington, Nova Scotia, Canada Age: 53</td>
<td>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.</td>
<td>Director of APUC since October 27, 2009. Trustee of the Fund since July 27, 2009</td>
<td>nil (^{2})</td>
</tr>
<tr>
<td>Name and Place of Residence</td>
<td>Principal Occupation</td>
<td>Served as Director or Officer of APUC from</td>
<td>Number of Common Shares</td>
</tr>
<tr>
<td>----------------------------</td>
<td>----------------------</td>
<td>------------------------------------------</td>
<td>-------------------------</td>
</tr>
<tr>
<td>DAVID BRONICHESKI</td>
<td>Mr. Bronicheski is the Chief Financial Officer of APUC. He has held various senior management positions including Executive Vice President and Chief Financial Officer of a publicly traded income trust providing local telephone, cable television and internet service. He was also Chief Financial Officer for a large public hospital in Ontario. David holds a Bachelor of Arts in economics (cum laude), a Bachelor of Commerce degree and an MBA. He is also a Chartered Accountant (CA).</td>
<td>Officer of APUC since October 27, 2009. Officer of the Fund since September 17, 2007.</td>
<td>38,300&lt;sup&gt;(7)(8)&lt;/sup&gt;</td>
</tr>
<tr>
<td>CHRISTOPHER K. JARRATT</td>
<td>Mr. Jarratt is currently the Vice Chairman of APUC. Mr. Jarratt is a founder and principal of Algonquin Power Corporation Inc., 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. (Chartered Director). He holds a Professional Engineer designation and an Honours Bachelor of Science degree from the University of Guelph.</td>
<td>Director of APUC since June 23, 2010.</td>
<td>406,423&lt;sup&gt;(7)(8)&lt;/sup&gt;</td>
</tr>
<tr>
<td>IAN E. ROBERTSON</td>
<td>Mr. Robertson is currently the President and Chief Executive Officer of APUC. Mr. Robertson is a founder and principal of Algonquin Power Corporation Inc., a private independent power developer formed in 1988. 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. (Chartered Director). 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</td>
<td>Director of APUC since June 23, 2010.</td>
<td>422,708&lt;sup&gt;(7)(8)&lt;/sup&gt;</td>
</tr>
<tr>
<td>MARY LOU MCDONALD</td>
<td>Ms. McDonald has been general counsel for APCo since April 2008 and was appointed Corporate Secretary of APUC on March 4, 2010. Prior to her position with APCo, she was in-house legal counsel for a division of Superior Plus LP. From 2000 to 2003, Ms. McDonald was an associate at the law firm of Macleod Dixon LLP in Calgary, Alberta and prior to that worked as an associate at a boutique energy law firm. Ms McDonald attended law at the University of Calgary and was called to the bar in 1994.</td>
<td>Officer of APUC since March 4, 2010.</td>
<td>1,500</td>
</tr>
</tbody>
</table>

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 the Fund on September 17, 2007.
Prior to becoming an officer of the Fund in September 2007, Mr. Bronicheski was the Chief Financial Officer of Amtelecom Income Fund from July 2003 to July 2007.

Messrs. Jarratt and Robertson, together with others, collectively own all of the issued and outstanding shares of APMI.

As consideration for payment of APUC’s acquisition of APMI’s interest in the management agreement, Mr. Robertson and Mr. Jarratt following shareholder approval at the Meeting each received 295,045 Common Shares.

Messrs. Jarratt, Robertson, and Bronicheski hold 378,061, 494,388, and 229,592 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.

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.

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 25, 2011, approximately 829,131 Common Shares representing 0.8% of the issued and outstanding Common Shares are beneficially owned, directly or indirectly, by Senior Officers and approximately 925,458 Common Shares representing 0.9% 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, Christopher Ball (Chairman), Kenneth Moore and George 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 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 the Fund, 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 Carlton 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, 2010 and December 31, 2009, KPMG LLP charged the following fees to APUC:

<table>
<thead>
<tr>
<th>Services</th>
<th>2010 Fees ($)</th>
<th>2009 Fees ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Audit Fees</td>
<td>648,000</td>
<td>580,000</td>
</tr>
<tr>
<td>Audit-Related Fees(1)</td>
<td>375,000</td>
<td>862,000</td>
</tr>
<tr>
<td>Tax Fees(2)</td>
<td>885,000</td>
<td>1,156,000</td>
</tr>
<tr>
<td>All Other Fees</td>
<td>Nil</td>
<td>Nil</td>
</tr>
</tbody>
</table>

Notes:
(1) For assurance and related services that are reasonably related to the performance of the audit or review of the Fund’s financial statements and not reported under Audit Fees, including services in connection with prospectus and securities filings, accounting advice, French translation services and financial statement audits of subsidiary companies.
(2) 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, George Steeves (chair), Chris Huskilson and Ken Moore, and management members Ian Robertson and Chris Jarratt. This CGC also serves as the director nominating and evaluating. The CGC is responsible for reviewing APUC’s corporate governance practices. The CGC will also consider from time to time 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, comprised of Directors Chris Huskilson (chair) and Chris Ball, and management members Ian Robertson and David Bronicheski. The Compensation Committee is responsible for reviewing directors’ compensation on an annual basis, or more frequently if required, in light of the risks involved in being an effective Director. In addition, the Compensation Committee will make recommendations to the directors regarding the compensation of executive officers of APUC and produce a report concerning executive compensation in compliance with Canadian securities law requirements.

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, 2010, 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 Energy, 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 2010 are as follows:

(a) Trafalgar

As reported in previous public filings of Algonquin, Trafalgar Power, Inc. and an affiliate (collectively, “Trafalgar”) commenced an action in 1999 in U.S. District Court against Algonquin, APMI and various other entities related to them in connection with, among other things, the sale of the Trafalgar Class B Note by Aetna Life Insurance Company to Algonquin and in connection with the foreclosure on the security for the Trafalgar Class B Note which includes interests in the Trafalgar entities and in the hydroelectric generating facilities in New York (the “Trafalgar Facilities”). In 2001, Trafalgar and other entities also filed for Chapter 11 reorganization in bankruptcy court and also filed a multi-count adversary complaint against certain APCo entities, which complaint was then transferred to the District Court. In 2006, the District Court decided that Aetna had complied with the provisions concerning the sale of the Trafalgar Class B Note, that Algonquin was therefore the holder and owner of the Trafalgar Class B Note, and that all other claims by Trafalgar with respect to the transfer of the Trafalgar Class B Note were without merit. Further, on November 6, 2008, the claims that were remaining in the District Court against Algonquin were dismissed by summary judgement. On October 22, 2009 Trafalgar filed an appeal from the November 6, 2008 summary judgement to the United States Court of Appeals for the Second Circuit. The Second Circuit Court of Appeals, among other things, on November 2, 2010 dismissed the claims against APCo in the civil proceedings. The bankruptcy proceedings are continuing.

(b) Côte Ste-Catherine Water Lease Dues

On December 19, 1996, the Attorney General of Québec (“Québec AG”) filed suit in Québec Superior Court against Algonquin Développement Côte Ste-Catherine Inc. (Développement Hydromea), a predecessor company to an Algonquin subsidiary. The Québec AG at trial claimed $5.4 million for amounts that the Algonquin entity had been paying to the federal authority under its water lease with the authority. The Algonquin entity brought the Attorney General of Canada into the proceedings. On March 27, 2009, the Superior Court dismissed the claim of the Québec AG. Québec AG appealed this decision on April 24, 2009, and the appeal was heard in January 2011. The Côte Ste-Catherine Facility currently pays water lease dues to the federal government, but if the Québec AG is successful in any appeal, an adjustment and/or increase of such amounts is possible.
9.2 Regulatory Actions

Except as disclosed elsewhere in this AIF, during the financial year ended December 31, 2010, 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, 2010, 2009, and 2008, 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 2010 (or prior to 2009 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) **Shareholder Rights Plan:** The Shareholder Rights Plan Agreement dated as of June 9, 2010 between APUC and CIBC Mellon Trust Company, as Rights Agent. The Rights Plan creates a right (which may only be exercised if a person acquires control of 20% or more of the Common Shares) for each Shareholder, other than the person that acquires 20% or more of the Common Shares, to acquire additional Common Shares at one-half of the market price at the time of exercise. Until the occurrence of certain specific events, the rights will trade with the Common Shares and be represented by certificates representing the Common Shares. The rights become exercisable only when a person, including any party related to it or acting jointly with it, acquires or announces its intention to acquire twenty percent or more of the outstanding Common Shares of APUC without complying with the Permitted Bid provisions of the Plan. Should a non-Permitted Bid be launched, each right would entitle each holder of Common Shares (other than the acquiring
person and persons related to it or acting jointly with it) to purchase additional Common Shares of APUC at a fifty percent discount to the market price at the time.

(b) 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 total consideration payable is U.S. $285.0 million. Granite State is a regulated electric distribution company providing electric service to over 43,000 customers in 21 communities in New Hampshire. EnergyNorth is a regulated natural gas distribution utility providing 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. The closings of the transactions are subject to certain conditions including state and federal regulatory approval, and are expected to occur in the fall of 2011.

(c) 2010 Subscription Agreement: Offering of Subscription Receipts dated as of December 9, 2010 from APUC to Emera, in which Emera agreed to a conditional treasury subscription of 12.0 million Common Shares at a price of $5.00 per Common Share representing an approximate 5% premium to APUC’s closing share price on December 8, 2010. Payment for the 2010 Subscription Receipts will be satisfied by delivery by Emera of a non-interest bearing promissory note in the amount of $60,000,000. Upon receipt by Emera that the conditions precedent to the closing of the National Grid transactions have occurred (other than payment of the purchase price), the promissory note will become due and payable and the rights evidenced by the 2010 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. In the event of termination of the 2010 Subscription Agreement, the promissory note will be returned to Emera for cancellation, and the parties will have no further obligations under the 2010 Subscription Agreement and the Subscription Receipts will be returned for cancellation.

(d) Liberty Water Private Placement: Liberty Water $50,000,000 5.60% Unsecured Notes due December 22, 2020 Note Purchase Agreement dated as of December 22, 2010, pursuant to which Liberty Water entered into a U.S. $50 million private placement debt financing. The notes are senior unsecured with a 10 year term bearing interest at 5.6%. The notes are interest only 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.

(e) Subscription and Unitholder Agreement dated April 22, 2009 (the “Subscription Agreement”) between Algonquin and Emera, pursuant to which Emera obtained a conditional treasury subscription of approximately 8.5 million trust units of Algonquin at a price of $3.25 per Trust 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. Delivery of Common Shares under the subscription receipts to occurred simultaneously with the closing of the acquisition of the California Utility on January 1, 2011. At closing, Emera exchanged these subscription receipts into 8.532 million APUC Common Shares at a purchase price of $3.25 per Common Shares. The proceeds of the subscription receipts were utilized to fund Liberty Energy’s ownership share of the cost of acquisition of the California Utility.

(f) Calpeco Private Placement: California Pacific Electric Company, LLC $45,000,000 5.19% Senior Unsecured Notes, Series A, due December 29, 2020 and $25,000 000 5.59% Senior
Unsecured Notes, Series B, due December 29, 2025, dated as of December 29, 2010 pursuant to which Calpeco entered into a $70 million senior unsecured private debt placement. The private placement is a senior unsecured private placement with U.S. institutional investors, backed solely by the California Utility assets. 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.

(g) **Red Lily Agreements**: Loan Agreement dated as of April 19, 2010 between Red Lily Wind Energy Partnership, as Borrower, and Integrated Private Debt Fund II LP and APUC, as Lenders. pursuant to which the Lenders agreed to fund the Red Lily project costs with $31 million of senior debt to be provided by Integrated Private Debt Fund II LP and with $17.5 million of senior and subordinated debt to be provided by APUC and APCo. APUC and/or certain subsidiaries also entered into agreements to provide services to and will receive fees for the development, construction, operation and supervision of the project, pursuant to a Supervisory Agreement, a Development and Construction Services Agreement, and an Operations Agreement, all dated April 19, 2010. In addition, a subsidiary of APCo, APT, entered into an Option Agreement dated April 19, 2010 among the Borrower, 7314507 Canada Inc., Red Lily Wind Energy Corp. and APT. Co has been granted an option to subscribe for a 75% equity interest in the project in exchange for its subordinated debt commitment, exercisable five years following commissioning of the project.

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, 2010.
### SCHEDULE A

**Renewable Energy - Hydroelectric and Wind Facilities**

<table>
<thead>
<tr>
<th>Generating Facility/Owner</th>
<th>Generating Capacity (kilowatts)</th>
<th>Location</th>
<th>Electricity Purchaser/2011 Power Purchase Rates(1)</th>
<th>Annual Average Expected Energy Production (MW-hrs)</th>
<th>Year of Expiry of Power Purchase Agreement</th>
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<tbody>
<tr>
<td><strong>Ontario Facilities</strong></td>
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<tr>
<td>Facility: Long Sault Rapids Facility (Hydroelectric)</td>
<td>18,000</td>
<td>Abitibi River near Cochrane, Ontario</td>
<td><strong>Electricity Purchaser:</strong> OEFC</td>
<td><strong>Rates:</strong> $0.09195/kW-hr (average estimate)</td>
<td>111,600</td>
</tr>
<tr>
<td>Owner: Algonquin Power (Long Sault) Partnership and N-R Power Partnership</td>
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<tr>
<td>Facility: Hurdman Dam Facility (Hydroelectric)</td>
<td>570</td>
<td>Mattawa River near Mattawa, Ontario</td>
<td><strong>Electricity Purchaser:</strong> Hydro One Inc.</td>
<td><strong>Rates:</strong> Paid on Hourly Spot Market Price</td>
<td>3,150</td>
</tr>
<tr>
<td>Owner: APFC</td>
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<tr>
<td>Facility: Burgess Dam Facility (Hydroelectric)</td>
<td>140</td>
<td>Muskoka River near Bala, Ontario</td>
<td><strong>Electricity Purchaser:</strong> OEFC</td>
<td><strong>Rates:</strong> Paid on Hourly Spot Market Price</td>
<td>950</td>
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<tr>
<td>Owner: APFC</td>
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<tr>
<td>Facility: Campbellford Facility (Hydroelectric)</td>
<td>4,000</td>
<td>Trent River near Campbellford, Ontario</td>
<td><strong>Electricity Purchaser:</strong> OEFC</td>
<td><strong>Rates:</strong> $0.04346/kW-hr (average estimate)</td>
<td>26,250</td>
</tr>
<tr>
<td>Generating Facility/Owner</td>
<td>Generating Capacity (kilowatts)</td>
<td>Location</td>
<td>Electricity Purchaser/ 2011 Power Purchase Rates(^{(3)})</td>
<td>Annual Average Expected Energy Production (MW-hrs)</td>
<td>Year of Expiry of Power Purchase Agreement</td>
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<tr>
<td>Québec Developments</td>
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</tbody>
</table>
| Facility: Saint-Alban Facility (Hydroelectric) | 8,200 | Ste-Anne River near the Village of Saint-Alban, Québec | **Electricity Purchaser:** Hydro-Québec  
**Rates:**  
$0.07609/kW-hr (Jan – Nov)  
$0.07837/kW-hr (Dec) | 37,300 | 2016 |
| Owner: SLI\(^{(4)}\) |                                 |          |                                                 |                                                 |                                          |
| Facility: Glenford Facility (Hydroelectric) | 4,950 | Ste-Anne River near the Village of Ste-Christine d’Auvergne, Québec | **Electricity Purchaser:** Hydro-Québec  
**Rates:**  
$0.07609/kW-hr (Jan – Nov)  
$0.07837/kW-hr (Dec) | 23,750 | 2020 |
| Owner: Glenford Partnership |                                 |          |                                                 |                                                 |                                          |
| Facility: Rawdon Facility (Hydroelectric) | 2,500 | Ouareau River near the Village of Rawdon, Québec | **Electricity Purchaser:** Hydro-Québec  
**Rates:**  
$0.07609/kW-hr (Jan – Nov)  
$0.07837/kW-hr (Dec) | 15,300 | 2014 |
| Owner: APFC |                                 |          |                                                 |                                                 |                                          |
| Facility: Côte Ste-Catherine Facility (Hydroelectric) | 11,120 | St. Lawrence River near the Town of Ste.-Catherine, Québec | **Electricity Purchaser:** Hydro-Québec  
**Rates:**  
Phase I  
Energy $0.04853/kW-hr  
Phase II  
Energy $0.06491/kW-hr  
Capacity $159.32/kilowatt  
Phase III  
Energy $0.06759/kW-hr  
Capacity $167.05/kilowatt  

* calculated over the average kilowatt output over the period December to March | Phase I: 15,500 | Phase I: 2021 |
| Owner: Mont-Laurier Partnership |                                 |          |                                                 |                                                 |                                          |

**Footnotes:**
\(^{(1)}\) The rates may vary depending on the terms of the agreement. 
\(^{(2)}\) The facilities are subject to the approval of the relevant authorities. 
\(^{(3)}\) The expected energy production is calculated based on the generating capacity and expected utilization. 
\(^{(4)}\) SLI stands for Société de l’Énergie de la Mauricie et de l’Estrie.
<table>
<thead>
<tr>
<th>Generating Facility/Owner</th>
<th>Generating Capacity (kilowatts)</th>
<th>Location</th>
<th>Electricity Purchaser/ 2011 Power Purchase Rates(^{(1)})</th>
<th>Annual Average Expected Energy Production (MW-hrs)</th>
<th>Year of Expiry of Power Purchase Agreement</th>
</tr>
</thead>
</table>
| **Facility:** Ste-Raphaël Facility (Hydroelectric) | 3,500 | Rivière de Sud near Québec City, Québec | **Electricity Purchaser:** Hydro-Québec  
**Rates:**  
$0.07609/kW-hr (Jan – Nov)  
$0.07837/kW-hr (Dec) | 22,550 | 2014 |
| **Owner:** APFC | | | | | |
| **Facility:** Mont Laurier Facility (Hydroelectric) | 2,725 | Rivière-du-Lièvre in the Town of Mont Laurier, Québec | **Electricity Purchaser:** Hydro-Québec  
**Rates:**  
$0.05803/kW-hr | 21,250 | 2027 |
| **Owner:** Mont-Laurier Partnership | | | | | |
| **Facility:** Rivière-du-Loup Facility (Hydroelectric) | 2,600 | Rivière-du-Loup near the Town of Rivière-du-Loup, Québec | **Electricity Purchaser:** Hydro-Québec  
**Rates:**  
$0.07609/kW-hr (Jan – Nov)  
$0.07837/kW-hr (Dec) | 17,250 | 2015 |
| **Owner:** APFC | | | | | |
| **Facility:** Hydraska Facility (Hydroelectric) | 2,250 | Yamaska River near the Town of St.-Hyacinthe, Québec | **Electricity Purchaser:** Hydro-Québec  
**Rates:**  
Summer Energy $0.06399/kW-hr  
Winter Energy $0.11734/kW-hr | 9,100 | 2014 |
| **Owner:** APT | | | | | |
| **Facility:** Ste-Brigitte Facility (Hydroelectric) | 4,200 | Nicolet River in the Municipality of Ste-Brigitte-des-Saults, Québec | **Electricity Purchaser:** Hydro-Québec  
**Rates:**  
$0.07609/kW-hr (Jan – Nov)  
$0.07837/kW-hr (Dec) | 12,750 | 2014 |
<p>| <strong>Owner:</strong> APFC | | | | | |</p>
<table>
<thead>
<tr>
<th>Generating Facility/Owner</th>
<th>Generating Capacity (kilowatts)</th>
<th>Location</th>
<th>Electricity Purchaser/ 2011 Power Purchase Rates(^{(3)})</th>
<th>Annual Average Expected Energy Production (MW-hrs)</th>
<th>Year of Expiry of Power Purchase Agreement</th>
</tr>
</thead>
</table>
| Facility: Belleterre Facility (Hydroelectric) | 2,200 | Winneway River in the Municipality of Laforce, Québec | Electricity Purchaser: Hydro-Québec  
Rates:  
Summer Energy: $0.06342/kW-hr  
Winter Energy: $0.11779/kW-hr  
Capacity: $156.75/kilowatt (over the average kilowatt output over the period December to March) | 11,250 | 2013 |
| Owner: APFC | | | | | |
| Facility: Donnacona Facility (Hydroelectric) | 4,800 | Jacques Cartier River near Donnacona, Québec | Electricity Purchaser: Hydro-Québec  
Rates: $0.07609/kW-hr (Jan – Nov)  
$0.07837/kW-hr (Dec) | 20,550 | 2022 |
| Owner: Donnacona Partnership | | | | | |
| Facility: St. Raphaël de Bellechasse Facility (Arthurville) (Hydroelectric) | 650 | Riviere du Sud downstream from Ste-Raphaël | Electricity Purchaser: Hydro-Québec  
Rates: $0.07609/kW-hr (Jan – Nov)  
$0.07837/kW-hr (Dec) | 2,900 | 2013 |
| Owner: APT | | | | | |
| Newfoundland Facility | | | | | |
| Facility: Rattle Brook Facility (Hydroelectric) | 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 |
| Owner: Rattlebrook Partnership | | | | | |
| New York Facilities | | | | | |
| Facility: Ogdensburg Facility (Hydroelectric) | 3,675 | Oswegatchie River near Ogdensburg, New York | Electricity Purchaser: National Grid  
Rates: US$0.04326/kW-hr (est)\(^{(6)}\) | 11,100 | 2011 |
<p>| Owner: Trafalgar(^{(5)}) | | | | | |</p>
<table>
<thead>
<tr>
<th>Generating Facility/Owner</th>
<th>Generating Capacity (kilowatts)</th>
<th>Location</th>
<th>Electricity Purchaser/ 2011 Power Purchase Rates(3)</th>
<th>Annual Average Expected Energy Production (MW-hrs)</th>
<th>Year of Expiry of Power Purchase Agreement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Facility: Forestport Facility (Hydroelectric)</td>
<td>3,300</td>
<td>Black River near Boonville, New York</td>
<td>Electricity Purchaser: National Grid Rates: US$0.04297/kW-hr (est) (6)</td>
<td>11,500</td>
<td>2011</td>
</tr>
<tr>
<td>Owner: Trafalgar(5)</td>
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<tr>
<td>Facility: Herkimer Facility (Hydroelectric)</td>
<td>1,680</td>
<td>West Canada Creek near Herkimer, New York</td>
<td>Electricity Purchaser: National Grid Rates: No target rate as the site is expected to be offline</td>
<td>0(7)</td>
<td>2011</td>
</tr>
<tr>
<td>Owner: Trafalgar(5)</td>
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<tr>
<td>Facility: Christine Falls Facility (Hydroelectric)</td>
<td>850</td>
<td>Sacandaga River near Clifton, New York</td>
<td>Electricity Purchaser: National Grid Rates: US $0.04167/kW-hr (est) (6)</td>
<td>3,300</td>
<td>2028</td>
</tr>
<tr>
<td>Owner: Christine Falls Corporation(5)</td>
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</tr>
<tr>
<td>Facility: Cranberry Lake Facility (Hydroelectric)</td>
<td>500</td>
<td>Oswegatchie River near Clifton, New York</td>
<td>Electricity Purchaser: National Grid Rates: US$0.04321/kW-hr (est) (6)</td>
<td>1,800</td>
<td>2011</td>
</tr>
<tr>
<td>Owner: Trafalgar(5)</td>
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<tr>
<td>Facility: Kayuta Lake Facility (Hydroelectric)</td>
<td>400</td>
<td>Black River near Boonville, New York</td>
<td>Electricity Purchaser: National Grid Rates: US$0.00824/kW-hr (est)</td>
<td>1,800</td>
<td>2028</td>
</tr>
<tr>
<td>Owner: Trafalgar(5)</td>
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<tr>
<td>Facility: Adams Facility (Hydroelectric)</td>
<td>350</td>
<td>Sandy Creek near Adams, New York</td>
<td>Electricity Purchaser: National Grid Rates: No target rate as the site is expected to be offline</td>
<td>0(7)</td>
<td>2028</td>
</tr>
<tr>
<td>Generating Facility/Owner</td>
<td>Generating Capacity (kilowatts)</td>
<td>Location</td>
<td>Electricity Purchaser/ 2011 Power Purchase Rates(1)</td>
<td>Annual Average Expected Energy Production (MW-hrs)</td>
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<tr>
<td>Kings Falls Facility</td>
<td>1,750</td>
<td>Deer River near Copenhagen, New York</td>
<td>Electricity Purchaser: National Grid Rates: US$0.04352/kW-hr(6)</td>
<td>3,000</td>
<td>2011</td>
</tr>
<tr>
<td>Tug Hill Energy, Inc.</td>
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<tr>
<td>Otter Creek Facility</td>
<td>530</td>
<td>Otter Creek in Craig, New York</td>
<td>Electricity Purchaser: National Grid Rates: US$0.04298/kW-hr (est)(6)</td>
<td>1,900</td>
<td>2011</td>
</tr>
<tr>
<td>Tug Hill Energy, Inc.</td>
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<tr>
<td>Phoenix Facility</td>
<td>3,500</td>
<td>Oswego River in Phoenix, New York</td>
<td>Electricity Purchaser: National Grid Rates: US$0.09205/kW-hr Flat Rate</td>
<td>11,250</td>
<td>2026</td>
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<tr>
<td>Oswego Hydro Partners L.P.</td>
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<tr>
<td>Beaver Falls Facility</td>
<td>2,500</td>
<td>Beaver River in Beaver Falls, New York</td>
<td>Electricity Purchaser: National Grid Rates: US$0.02989/kW-hr (est)</td>
<td>15,400</td>
<td>2019</td>
</tr>
<tr>
<td>Algonquin Power (Beaver Falls) LLC</td>
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<tr>
<td>Burt Dam Facility</td>
<td>600</td>
<td>18 Mile Creek near Newfane, New York</td>
<td>Electricity Purchaser: National Grid Rates: US$0.04354/kW-hr (est)(6)</td>
<td>1,950</td>
<td>2011</td>
</tr>
<tr>
<td>Burt Dam Partnership</td>
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<tr>
<td>Hollow Dam Facility</td>
<td>900</td>
<td>Oswegatchie River near Gouverneur, New York</td>
<td>Electricity Purchaser: National Grid Rates: US$0.04328/kW-hr (est)(6)</td>
<td>4,050</td>
<td>2011</td>
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<tr>
<td>Hollow Dam Partnership</td>
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<tr>
<td>Generating Facility/Owner</td>
<td>Generating Capacity (kilowatts)</td>
<td>Location</td>
<td>Electricity Purchaser/2011 Power Purchase Rates (1)</td>
<td>Annual Average Expected Energy Production (MW-hrs)</td>
<td>Year of Expiry of Power Purchase Agreement</td>
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<tr>
<td><strong>New England Facilities</strong></td>
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<tr>
<td>Facility: Greggs Falls Facility (Hydroelectric)</td>
<td>3,500</td>
<td>Piscataquog River near the Town of Goffstown, New Hampshire</td>
<td>Electricity Purchaser: Public Service Company of New Hampshire (“PSNH”)</td>
<td>10,450</td>
<td>60 day written notice</td>
</tr>
<tr>
<td>Owner: Greggs Falls Partnership</td>
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<td></td>
<td>Rates: US$0.05058/kW-hr (est) (8)</td>
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<tr>
<td>Facility: Pembroke Facility (Hydroelectric)</td>
<td>2,600</td>
<td>Suncook River near the Town of Pembroke, New Hampshire</td>
<td>Electricity Purchaser: PSNH</td>
<td>9,750</td>
<td>60 day written notice</td>
</tr>
<tr>
<td>Owner: Pembroke Hydro Associates Limited Partnership(10)</td>
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<td></td>
<td>Rates: US$0.05159/kW-hr (est) (8)</td>
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<tr>
<td>Facility: Clement Facility (Hydroelectric)</td>
<td>2,400</td>
<td>Winnipesaukee River near the Town of Tilton, New Hampshire</td>
<td>Electricity Purchaser: PSNH</td>
<td>10,700</td>
<td>60 day written notice</td>
</tr>
<tr>
<td>Owner: Clement Dam Hydroelectric LLC (11)</td>
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<td></td>
<td>Rates: US$0.05242/kW-hr (est) (8)</td>
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<tr>
<td>Facility: Franklin Facility (Hydroelectric)</td>
<td>River Bend 1,600 Steven’s Mill 200</td>
<td>Winnipesaukee River near the Town of Franklin, New Hampshire</td>
<td>Electricity Purchaser: PSNH</td>
<td>River Bend 6,800 Steven’s Mill 950</td>
<td>60 day written notice – both sites</td>
</tr>
<tr>
<td>Owner: Franklin Power LLC (8)</td>
<td></td>
<td></td>
<td>Rates: River Bend US$0.04803/kW-hr (est) (8) Steven’s Mill US$0.05292/kW-hr (est) (8)</td>
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</tr>
<tr>
<td>Facility: Lochmere Facility (Hydroelectric)</td>
<td>1,200</td>
<td>Winnipesaukee River near Lochmere, New Hampshire</td>
<td>Electricity Purchaser: PSNH</td>
<td>4,150</td>
<td>60 day written notice</td>
</tr>
<tr>
<td>Owner: HDI Partnership</td>
<td></td>
<td></td>
<td>Rates: US$0.05179/kW-hr (est) (8)</td>
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<tr>
<td>Generating Facility/Owner</td>
<td>Generating Capacity (kilowatts)</td>
<td>Location</td>
<td>Electricity Purchaser/ 2011 Power Purchase Rates</td>
<td>Annual Average Expected Energy Production (MW-hrs)</td>
<td>Year of Expiry of Power Purchase Agreement</td>
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</tbody>
</table>
| Facility: Lakeport Facility (Hydroelectric) | 600 | Winnipesaukee River near Laconia, New Hampshire | Electricity Purchaser: PSNH  
Rates: US$0.05185/kW-hr (est) | 2,450 | 60 day written notice |
| Owner: Lakeport Corporation | | | | | |
| Facility: Milton Facility (Hydroelectric) | 1,335 | Salmon River near the Town of Milton, New Hampshire | Electricity Purchaser: PSNH  
Rates: No target rate as the site is expected to be offline | 0 | 60 day written notice |
| Owner: SFR Hydro Corporation | | | | | |
| Facility: Mine Falls Facility (Hydroelectric) | 3,000 | Nashua River near the City of Nashua, New Hampshire | Electricity Purchaser: PSNH  
Rates: US $0.05139/kW-hr (est) | 11,400 | 60 day written notice |
| Owner: Mine Falls Limited Partnership | | | | | |
| Facility: Great Falls Facility (Hydroelectric) | 10,950 | Passaic River near the City of Paterson, New Jersey | Electricity Purchaser: Public Service Electric and Gas Company  
Rates: US $0.05491/kW-hr (est) | 23,350 | 60 day written notice |
| Owner: Great Falls Partnership | | | | | |
| Facility: Moretown Facility (Hydroelectric) | 1,200 | Mad River near Moretown, Vermont | Electricity Purchaser: Vermont Power Exchange, Inc.  
Rates: $0.10702/kW-hr (average estimate) | 2,100 | 2018 |
<p>| Owner: Moretown Partnership | | | | | |</p>
<table>
<thead>
<tr>
<th>Generating Facility/Owner</th>
<th>Generating Capacity (kilowatts)</th>
<th>Location</th>
<th>Electricity Purchaser/2011 Power Purchase Rates(^{(1)})</th>
<th>Annual Average Expected Energy Production (MW-hrs)</th>
<th>Year of Expiry of Power Purchase Agreement</th>
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</thead>
<tbody>
<tr>
<td><strong>Western Canada Facility</strong></td>
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<tr>
<td>Facility: Dickson Dam Facility (Hydroelectric)</td>
<td>15,000</td>
<td>Innisfail, Alberta</td>
<td><strong>Electricity Purchaser:</strong> TransAlta Utilities Corporation</td>
<td><strong>Rates:</strong> Energy: $0.0619/kW-hr</td>
<td><strong>65,900</strong></td>
</tr>
<tr>
<td>Owner: APOT</td>
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<tr>
<td><strong>Maritime Facilities</strong></td>
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</tr>
<tr>
<td>Facility: Tinker Facility (Hydroelectric)</td>
<td>33,500</td>
<td>Perth-Andover, New Brunswick</td>
<td><strong>Electricity Purchaser:</strong> Maine Gen Co. Town of Perth-Andover</td>
<td><strong>Rates:</strong> Maine Gen Co.: US $0.071/kWhr (net of transmission charges – variable monthly) Town of Perth Andover: $0.065/kWh CDN (net of transmission charges – variable monthly)</td>
<td><strong>124,000</strong></td>
</tr>
<tr>
<td>Owner: APT</td>
<td></td>
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</tr>
<tr>
<td>Facility: Caribou Facility (Hydroelectric)</td>
<td>900</td>
<td>Caribou, Maine</td>
<td><strong>Electricity Purchaser:</strong> AES</td>
<td><strong>Rates:</strong> Energy - US $0.050/kWhr</td>
<td><strong>5,050</strong></td>
</tr>
<tr>
<td>Owner: Maine Gen Co.</td>
<td></td>
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<tr>
<td>Facility: Squa Pan Facility (Hydroelectric)</td>
<td>1,400</td>
<td>Squa Pan Lake, near Caribou Maine</td>
<td><strong>Electricity Purchaser:</strong> AES</td>
<td><strong>Rates:</strong> Energy - US $0.050/kWhr Reserve Market: variable monthly US $0.3/kW-hr (average estimate)</td>
<td><strong>700</strong></td>
</tr>
<tr>
<td>Generating Facility/Owner</td>
<td>Generating Capacity (kilowatts)</td>
<td>Location</td>
<td>Electricity Purchaser/2011 Power Purchase Rates(1)</td>
<td>Annual Average Expected Energy Production (MW-hrs)</td>
<td>Year of Expiry of Power Purchase Agreement</td>
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</tr>
<tr>
<td><strong>Wind Facilities</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Facility:</strong> Wind</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>St. Leon Facility</td>
<td>99,000</td>
<td>St. Leon, Manitoba</td>
<td>Electricity Purchaser: Manitoba Hydro</td>
<td>372,000</td>
<td>2025 + one 5 year extension</td>
</tr>
<tr>
<td>Owner: St. Leon LP</td>
<td></td>
<td></td>
<td>Rates:</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Dependable $ /kW-hr (average estimate)</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Non-dependable $ /kW-hr (average estimate)</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Rates indexed annually to CPI in May.</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>WPPI $ 0.0100/kW-hr</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Facility:</strong> Wind</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Red Lily (Wind)</td>
<td>26,400</td>
<td>Saskatchewan</td>
<td>Electricity Purchaser: SaskPower</td>
<td>88,000</td>
<td>2036</td>
</tr>
<tr>
<td>Owner:</td>
<td></td>
<td></td>
<td>Rates:</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Facility:</strong> Wind</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Amherst Island (Wind)</td>
<td>75,000</td>
<td>Stella, Ontario</td>
<td>n/a (Under Development)</td>
<td>247,000</td>
<td>n/a</td>
</tr>
<tr>
<td><strong>Facility:</strong> Wind</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Saint-Damase (Wind)</td>
<td>25,000</td>
<td>Saint-Damase, Québec</td>
<td>n/a (Under Development)</td>
<td>86,000</td>
<td>n/a</td>
</tr>
<tr>
<td><strong>Facility:</strong> Wind</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Val-Éo (Wind)</td>
<td>25,000</td>
<td>Saint-Gédéon, Québec</td>
<td>n/a (Under Development)</td>
<td>66,000</td>
<td>n/a</td>
</tr>
<tr>
<td><strong>Facility:</strong> Wind</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Morse (Wind)</td>
<td>20,000</td>
<td>Morse, Saskatchewan</td>
<td>n/a (Under Development)</td>
<td>75,000</td>
<td>n/a</td>
</tr>
</tbody>
</table>

Notes:
(1) 2011 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) No agreement has been obtained for a long-term lease; the current lease is on a month-to-month basis.
(5) APC provides Trafalgar with certain operational services in respect of the Trafalgar Facilities.
(6) These rates reflect the estimated Avoided Costs of National Grid.
(7) Scheduled to be offline for repairs in 2011. No decision has been made as to the timing of repairing these Facilities.
(8) PSNH purchases the energy produced by these generating stations at the ISO-NE. market rates. These agreements are cancellable on 60 days written notice.
## SCHEDULE B

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

<table>
<thead>
<tr>
<th>Generating Facility/Owner</th>
<th>Generating Capacity (kilowatts)</th>
<th>Location</th>
<th>Electricity Purchaser/2011 Power Purchase Rates</th>
<th>Annual Average Expected Energy Production (MW-hrs)</th>
<th>Year of Expiry of Power Purchase Agreement</th>
<th>Year of Expiry of Lease</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Thermal - Biomass Facility</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Facility: Valley Power Facility (Biomass)</td>
<td>12,000</td>
<td>Drayton Valley, Alberta</td>
<td><strong>Electricity Purchaser:</strong> TransAlta Utilities Corporation</td>
<td>74,000$^{(1)}$</td>
<td>2014</td>
<td>Owned</td>
</tr>
<tr>
<td>Owner: Valley Power L.P.</td>
<td></td>
<td></td>
<td><strong>Rates:</strong> Energy: $0.0709/kW-hr</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

| **Thermal - Cogeneration Facilities** |                                 |                             |                                               |                                                  |                                          |                         |
| Facility: Sanger Facility (Cogeneration) | 56,000                          | Sanger, California         | **Electricity Purchaser:** PG&E               | 133,000                                          | 2021                                | Owned                  |
| Owner: Sanger LLC$^{(1)}$ |                                 |                             | **Rates:** Period A PG&E Avoided Cost - US0.046/ kW-hr (estimated average)*
|                                 |                                 |                             | Period B US $0. 047/ kW-hr (estimated average)*
|                                 |                                 |                             | * subject to gas price indexing |                                                 |                                          |                         |
|                                 |                                 |                             | **Capacity** - US$ 190 per kW/year up to 38,000 kW-hrs + bonus of 18%
|                                 |                                 |                             | (80% earned May – Oct) |                                                 |                                          |                         |

| Facility: Windsor Locks Facility (Cogeneration) | 56,000                          | Windsor Locks, Connecticut | **Electricity Purchaser:** ISO New England | 182,000                                          | Merchant                             | 2018                    |
| Owner: Algonquin Windsor Locks LLC$^{(1)}$ |                                 |                             | **Rates:** Market Rates , included hourly energy, forward capacity and forward reserve payments
|                                 |                                 |                             | Mill/NGC - US$0. 053/kW-hr* Capacity $197,000**
|                                 |                                 |                             | Steam - DNM/NGC - US$7.90/1000lbs* Capacity $125,000
|                                 |                                 |                             | * Estimated average rate, includes variable component based on natural gas prices.
|                                 |                                 |                             | **Estimated average monthly rate, charges are CPI indexed.
|                                 |                                 |                             | Capacity Market and Spot Market – market prices |                                                 |                                          |                         |

| Facility: Brampton Cogeneration Inc. (Cogeneration) | N/A                             | Brampton, Ontario          | **Electricity Purchaser:** N/A               | 675 million lbs of steam                       | 2024                                | N/A                     |
| Owner: APOT |                                 |                             | **Rates:** Steam - Normapac $7.47/1000lbs*
|                                 |                                 |                             | Capacity $102,700**
<p>|                                 |                                 |                             | * Estimated average rate, includes variable component based on natural |                                                 |                                          |                         |</p>
<table>
<thead>
<tr>
<th>Generating Facility/Owner</th>
<th>Generating Capacity (kilowatts)</th>
<th>Location</th>
<th>Electricity Purchaser/2011 Power Purchase Rates</th>
<th>Annual Average Expected Energy Production (MW-hrs)</th>
<th>Year of Expiry of Power Purchase Agreement</th>
<th>Year of Expiry of Lease</th>
</tr>
</thead>
<tbody>
<tr>
<td>Facility: EFW Facility (Energy from Waste)</td>
<td>10,100</td>
<td>Brampton, Ontario</td>
<td><strong>Electricity Purchaser:</strong> OEFIC</td>
<td>7,500</td>
<td>2012</td>
<td>Owned</td>
</tr>
<tr>
<td><strong>Owner:</strong> Algonquin Power Energy from Waste Inc.</td>
<td></td>
<td></td>
<td><strong>Rates:</strong></td>
<td></td>
<td><strong>Gas prices.</strong></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td><strong>Estimated average monthly rate, charges are partially CPI indexed.</strong></td>
<td></td>
<td><strong>Tipping – Peel – $91/tonne up to 127,900 tonnes, $66 tonnes thereafter</strong></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td><strong>Waste rates subject to monthly CPI indexing</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Thermal - Diesel**

| Facility: Tinker Facility (Diesel) | 1,000                          | Perth-Andover, New Brunswick | **Electricity Purchaser:** AES | 0(2) 2011 Owned | 2011 | Owned |
| **Owner:** Tinker Gen Co. |                                 |                       | **Rates:**                      |                  | 0(2) | 2011 | Owned |
|                          |                                 |                       | **Capacity – US $2.875/kw-mo** |                  |      |      |      |

| Facility: Caribou Facility (Diesel) | 7,000                          | Caribou, Maine            | **Electricity Purchaser:** Not under contract. | 0(2) 2011 Owned | 2011 | Owned |
| **Owner:** Maine Gen Co. |                                 |                       | **Rates:**                       |                  | 0(2) | 2011 | Owned |
|                          |                                 |                       | – N/A                            |                  |      |      |      |

<p>| Facility: Flo’s Inn Facility (Diesel) | 4,000                          | Caribou, Maine            | <strong>Electricity Purchaser:</strong> AES | 0(2) 2011 Owned | 2011 | Owned |
| <strong>Owner:</strong> Maine Gen Co. |                                 |                       | <strong>Rates:</strong>                      |                  | 0(2) | 2011 | Owned |
|                          |                                 |                       | <strong>Capacity – US $2.875/kw-mo</strong> |                  |      |      |      |</p>
<table>
<thead>
<tr>
<th>Generating Facility/Owner</th>
<th>Generating Capacity (kilowatts)</th>
<th>Location</th>
<th>Electricity Purchaser/ 2011 Power Purchase Rates</th>
<th>Annual Average Expected Energy Production (MW-hrs)</th>
<th>Year of Expiry of Power Purchase Agreement</th>
<th>Year of Expiry of Lease</th>
</tr>
</thead>
<tbody>
<tr>
<td>Steam</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Facility: Caribou Facility</td>
<td>21,700</td>
<td>Caribou, Maine</td>
<td><strong>Electricity Purchaser</strong>: Not Under Contract</td>
<td>0(2)</td>
<td>2011</td>
<td>Owned</td>
</tr>
<tr>
<td>(Steam)</td>
<td></td>
<td></td>
<td><strong>Rates</strong>: N/A</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Owner: Maine Gen Co.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Notes:
(1) This entity is a subsidiary of APFA.
(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.
(3) 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 2011.
<table>
<thead>
<tr>
<th>Utility</th>
<th>Owner(1)</th>
<th>Location</th>
<th>Type of Utility</th>
<th>December 31, 2010 Connections</th>
<th>Rates</th>
</tr>
</thead>
<tbody>
<tr>
<td>Black Mountain</td>
<td>Black Mountain Sewer</td>
<td>Carefree, Arizona</td>
<td>Wastewater</td>
<td>2,173</td>
<td>Residential US $65.24 (standard monthly rate)</td>
</tr>
<tr>
<td>Gold Canyon</td>
<td>Gold Canyon Sewer Company</td>
<td>Gold Canyon, Arizona</td>
<td>Wastewater</td>
<td>7,315</td>
<td>Residential US $52.40 (standard monthly rate)</td>
</tr>
<tr>
<td>Bella Vista</td>
<td>Bella Vista Water Co., Inc.</td>
<td>Sierra Vista, Arizona</td>
<td>Water Distribution</td>
<td>8,998</td>
<td>Residential US $26.75 (Average monthly rate)</td>
</tr>
<tr>
<td>Tall Timbers</td>
<td>Tall Timbers Utility Company, Inc.</td>
<td>Tyler, Texas</td>
<td>Wastewater</td>
<td>1,920</td>
<td>Residential US $54.93 (standard monthly rate)</td>
</tr>
<tr>
<td>Woodmark</td>
<td>Woodmark Utilities, Inc.</td>
<td>Tyler, Texas</td>
<td>Wastewater</td>
<td>1,699</td>
<td>Residential US $47.76 (standard monthly rate)</td>
</tr>
<tr>
<td>Litchfield Park</td>
<td>Litchfield Park Service Company</td>
<td>Litchfield, Park, Arizona</td>
<td>Wastewater</td>
<td>18,536</td>
<td>Residential US $38.99 (3)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Water Distribution</td>
<td>16,533</td>
<td>Commercial US $65.93 (3)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>US $39.77 (3) (Average residential rate)</td>
</tr>
<tr>
<td>Fox River</td>
<td>AWRI</td>
<td>Sheridan, Illinois</td>
<td>Wastewater</td>
<td>219</td>
<td>US $240.08</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Water Distribution</td>
<td>220</td>
<td>US $141.61</td>
</tr>
<tr>
<td>Timber Creek</td>
<td>AWRM</td>
<td>DeSoto, Missouri</td>
<td>Wastewater</td>
<td>22</td>
<td>US $16.00 min &amp; US $17.24/1000 gal.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Water Distribution</td>
<td>31</td>
<td>US $8.96 min. &amp; US $5.96/1000 gal.</td>
</tr>
<tr>
<td>Holliday Hills</td>
<td>AWRM</td>
<td>Branson, Missouri</td>
<td>Water Distribution</td>
<td>481</td>
<td>US $8.96 min. &amp; US $5.96/1000 gal.</td>
</tr>
<tr>
<td>Ozark Mountain</td>
<td>AWRM</td>
<td>Kimberling City, Missouri</td>
<td>Wastewater</td>
<td>241</td>
<td>US $16.00 min &amp; US $17.24/1000 gal.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Water Distribution</td>
<td>255</td>
<td>US $8.96 min. &amp; US $5.96/1000 gal.</td>
</tr>
<tr>
<td>Holly Lake Ranch</td>
<td>AWRT</td>
<td>Hawkins, Texas</td>
<td>Wastewater</td>
<td>131</td>
<td>US $128.53 min &amp; US $3.65/1000 gal.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Water Distribution</td>
<td>1,898</td>
<td>US $39.81 min. &amp; US $1.30/1000 gal.</td>
</tr>
<tr>
<td>Utility</td>
<td>Owner(1)</td>
<td>Location</td>
<td>Type of Utility</td>
<td>December 31, 2010 Connections</td>
<td>Rates</td>
</tr>
<tr>
<td>--------------------</td>
<td>---------------------------</td>
<td>---------------------</td>
<td>----------------</td>
<td>-------------------------------</td>
<td>------------------------------------------------------------</td>
</tr>
<tr>
<td>Big Eddy</td>
<td>AWRT</td>
<td>Flint, Texas</td>
<td>Wastewater</td>
<td>411</td>
<td>US $128.53 min &amp; US $3.65/1000 gal. US $39.81 min. &amp; $1.30/1000 gal</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Water Distribution</td>
<td>663</td>
<td></td>
</tr>
<tr>
<td>Piney Shores</td>
<td>AWRT</td>
<td>Conroe, Texas</td>
<td>Wastewater</td>
<td>269</td>
<td>US $128.53 min &amp; US $3.65/1000 gal. US $39.81 min. &amp; $1.30/1000 gal</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Water Distribution</td>
<td>273</td>
<td></td>
</tr>
<tr>
<td>Hill Country</td>
<td>AWRT</td>
<td>New Braunfels, Texas</td>
<td>Wastewater</td>
<td>378</td>
<td>US $128.53 min &amp; US $3.65/1000 gal. US $39.81 min. &amp; $1.30/1000 gal</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Water Distribution</td>
<td>225</td>
<td></td>
</tr>
<tr>
<td>Rio Rico</td>
<td>Rio Rico Utilities Inc.</td>
<td>Rio Rico, Arizona</td>
<td>Wastewater</td>
<td>2,201</td>
<td>US $56.36 (residential rates) US $6.45 min. &amp; 0-4,000 gal – US $1.44/1,000 gal 4,001-10,000 gal – US $1.70/1,000 gal &gt;10,000 gal – US $1.90/1,000 gal</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Water Distribution</td>
<td>6,730</td>
<td></td>
</tr>
<tr>
<td>Northern Sunrise</td>
<td>Northern Sunrise Water Company Inc.</td>
<td>Sierra Vista, Arizona</td>
<td>Water Distribution</td>
<td>355</td>
<td>US $31.00 min &amp; 0-5,000 gal – US $2.00/1,000 gal 5,001-10,000 gal – US $2.75/1,000 gal &gt;10,000 gal – US $3.90/1,000 gal</td>
</tr>
<tr>
<td>Southern Sunrise</td>
<td>Southern Sunrise Water Company Inc.</td>
<td>Sierra Vista, Arizona</td>
<td>Water Distribution</td>
<td>860</td>
<td>US $31.00 min &amp; 0-5,000 gal – US $2.00/1,000 gal 5,001-10,000 gal – US $2.75/1,000 gal &gt;10,000 gal – US $3.90/1,000 gal</td>
</tr>
<tr>
<td>Entrada Del Oro(2)</td>
<td>Entrada Del Oro Sewer Company</td>
<td>Gold Canyon, Arizona</td>
<td>Wastewater</td>
<td>302</td>
<td>US $76.00 (standard monthly rate)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Water Distribution</td>
<td>156</td>
<td>US $166.68</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Wastewater Collection</td>
<td>156</td>
<td>US $165.45</td>
</tr>
<tr>
<td>Total connections</td>
<td></td>
<td></td>
<td></td>
<td>73,651</td>
<td></td>
</tr>
</tbody>
</table>

Notes:
(1) Each of these entities is a wholly-owned subsidiary of Liberty Water Co.
(2) Liberty Water Co. currently holds a beneficial interest in the shares of the company pending regulatory approval of its acquisition.
(3) Effective rates based on upon implementation of rates awarded on December 1, 2010 at the Litchfield Facility.
## SCHEDULE D

### Wastewater and Water Distribution Facilities

<table>
<thead>
<tr>
<th>Utility</th>
<th>Owner(1)</th>
<th>Location</th>
<th>Type of Utility</th>
<th>December 31, 2010 Connections</th>
<th>Rates</th>
</tr>
</thead>
<tbody>
<tr>
<td>Calpeco</td>
<td>California Pacific Electric Company, LLC</td>
<td>Lake Tahoe, California</td>
<td>Electricity Distribution</td>
<td>48,000</td>
<td>Residential Rates – Monthly Charge $6.62. plus $0.10864/kwh for baseline usage; $0.13696 for excess usage</td>
</tr>
</tbody>
</table>
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
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. **RENUMERATION 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.
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, ramifications 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 therefor should also be reported to the Committee;

(C) other material written communications between the external auditor and Management, such as any management letter, schedule of unadjusted differences, listing of adjustments and reclassifications not recorded, management representation letter, report on observations and recommendations on internal controls, engagement letter and independence letter;

(D) major issues regarding financial statement presentations;

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

(F) the effect of regulatory and accounting initiatives, as well as off balance sheet structures, on the financial statements of the Corporation; and
(G) the adequacy of the Corporation’s internal controls and any special audit steps adopted in light of control deficiencies.

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

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

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

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

(b) External Auditor

(i) Authority with Respect to External Auditor – As representative of the Corporation’s shareholders and as a committee of the Board, the Committee shall be directly responsible for the appointment, compensation, retention, termination and oversight of the work of the external auditor (including, without limitation, resolution of disagreements between Management and the auditor regarding financial reporting) for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the Corporation. In this capacity, the Committee shall have sole authority for recommending the person to be proposed to the Corporation’s shareholders for appointment as external auditor, whether at any time the incumbent external auditor should be removed from office, and the compensation of the external auditor. The Committee shall require the external auditor to confirm in an engagement letter to the Committee each year that the external auditor is accountable to the Board and the Committee as representatives of shareholders and that it will report directly to the Committee.

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

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

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

(B) In accordance with applicable laws and regulations, the Committee shall pre–approve any non–audit services (including, without limitation, fees therefor) provided to the Corporation or its subsidiaries by the external auditor or any auditor of any such subsidiary and shall consider whether these services are compatible with the external auditor’s independence, including, without limitation, the nature and scope of the specific non–audit services to be performed and whether the audit process would require the external auditor to review any advice rendered by the external auditor in connection with the provision of non audit services. The 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 Section 5741 of the CICA Handbook – Assurance relating to the conduct of the audit.
(c) **Internal Audit Function – Controls**

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

(ii) **Oversight of Internal Controls** – The Committee shall oversee Management’s design and implementation of and reporting on the Corporation’s internal controls and review the adequacy and effectiveness of Management’s financial information systems and internal controls. The Committee shall periodically review and approve the mandate, plan, budget and staffing of internal audit personnel. The Committee shall direct Management to make any changes it deems desirable 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.
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 cooperation 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’s 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.
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”. 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 specified required by law, APUC undertakes no obligation to update any forward-looking statements or information to reflect new information, subsequent or otherwise.