ALGONQUIN POWER & UTILITIES CORP.

ANNUAL INFORMATION FORM

March 30, 2015

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

Caution concerning forward-looking statements

Certain statements included in this AIF contain information that is forward-looking within the meaning of certain securities laws, including information and statements regarding prospective results of operations, financial position or cash flows. Forward-looking information is included throughout this Annual Information Form, including among other places, under the heading "General Development of the Business", "Description of the Business" and "Legal Proceedings and Regulatory Actions". These statements and information are forward-looking, and are based on factors or assumptions that were applied in drawing a conclusion or making a forecast or projection, including assumptions based on historical trends, current conditions and expected future developments, and other factors believed to be appropriate in the circumstances.

Since forward-looking statements relate to future events and conditions, by their very nature they require making assumptions and involve inherent risks and uncertainties. APUC cautions that although it is believed that the assumptions are reasonable in the circumstances, these risks and uncertainties give rise to the possibility that actual results may differ materially from the expectations set out in the forward-looking statements. Material risk factors include those set out in this AIF under "Risk Factors". Readers are cautioned that such risks and uncertainties may cause APUC's actual results to vary materially from those expressed in, or implied by, the forward-looking statements and information. Given these risks, undue reliance should not be placed on these forward-looking statements, which apply only as of their dates. Other than as specifically required by law, APUC undertakes no obligation to update any forward-looking statements or information to reflect new information, subsequent or otherwise.

Non-GAAP Financial Measures

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

Use of Non-GAAP Financial Measures

EBITDA

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

Adjusted funds from operations

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

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

Adjusted net earnings

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

Net energy sales

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

Net utility sales

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

1. CORPORATE STRUCTURE

1.1 Name, Address and Incorporation

Algonquin Power & Utilities Corp. was originally incorporated under the Canada Business Corporations Act on August 1, 1988 as Traduction Militech Translation Inc. Pursuant to articles of amendment dated August 20, 1990 and January 24, 2007, the Corporation amended its articles to change its name to Société Hydrogenique Incorporée – Hydrogenics Corporation and Hydrogenics Corporation – Corporation Hydrogenique, respectively. Pursuant to a certificate and articles of arrangement dated October 27, 2009, the Corporation, among other things, created a new class of common shares, transferred its existing operations to a newly formed independent corporation, exchanged new common shares for all of the trust units of Algonquin Power Co. (the "**Unit Exchange**") and changed its name to Algonquin Power & Utilities Corp. The head and principal office of APUC is located at Suite 100, 354 Davis Road, Oakville, Ontario, L6J 2X1.

Unless the context indicates otherwise, references in this AIF to "**APUC**" or the "**Company**" include, for reporting purposes only, the direct or indirect subsidiary entities of APUC and partnership interests held by APUC and its subsidiary entities. Such use of "**APUC**" or the "**Company**" to refer to these other legal entities and partnership interests does not constitute a waiver by APUC or such entities or partnerships of their separate legal status for any purpose.

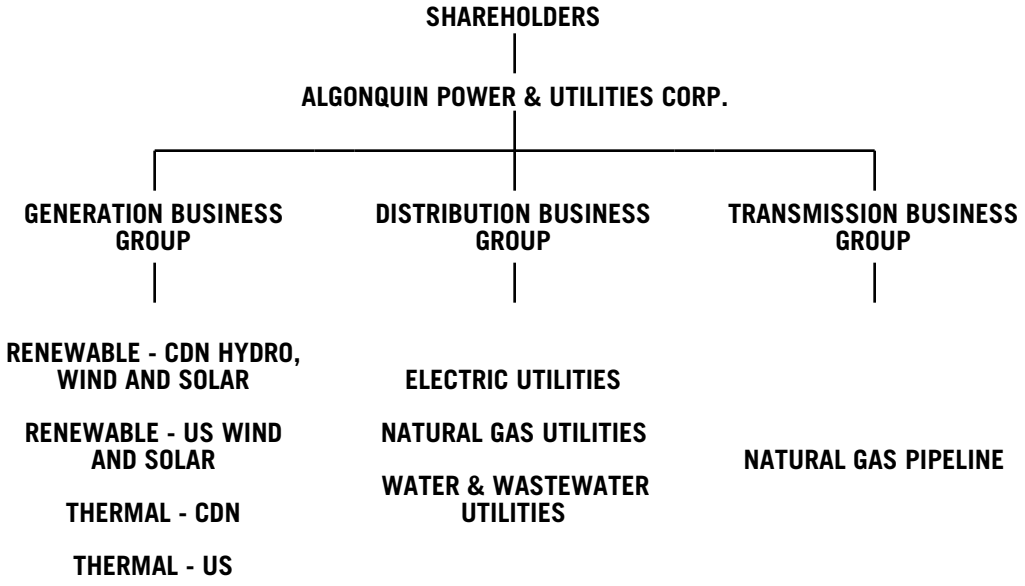
1.2 Intercorporate Relationships

1.2.1 Subsidiaries

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

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

The following chart summarizes the major lines of business.



The major chains are described below, including details on the legal entities that comprise these chains and the facilities they own. Additional information on the facilities is described in Schedules A, B, C, D, and E.

(i) Generation Business Group

Generation Business Group Chain Entities

APCo is the sole beneficiary of APT. APCo also owns 100% of the Class A common shares of APCH, an Ontario corporation. All of the Class B common shares of APCH are owned by St. Leon Wind Energy LP.. Also, APCo owns 100.0% of the issued and outstanding shares of Cornwall Solar Inc., which owns a solar power development project in Cornwall, Ontario.

APT Group

APT forms part of the APCo business unit. APT is an unincorporated open ended trust created by a declaration of trust dated June 30, 2000 in accordance with the laws of the Province of Ontario. APT owns all of the trust units of APOT.

APT controls the entities that own some of the Canadian hydroelectric facilities. APT owns all of the trust units in KMS Power Income Fund, an unincorporated open ended trust created by a declaration of trust dated February 18, 1997 in accordance with the laws of the Province of Alberta. This trust owns all of the outstanding common shares of Algonquin Power Energy From Waste Inc. ("**APEFW**"), an Ontario corporation whose assets and operations were sold to a third party effective April 4, 2014. APT directly owns a 2% limited partnership interest in the Algonquin Power (Mont-Laurier) Limited Partnership, a Québec limited partnership, which owns the Mont-Laurier Hydro Facility and the Côte Ste.-Catherine Hydro Facility, while APEFW owns the remaining 98% partnership interests, comprised of a 86.5% limited partnership interest and an 11.5% general partnership interest. APEFW has issued two classes of preferred shares: Class A preferred shares which are 100% owned by APCH, and Class B preferred shares which are 100% owned by APT.

APT directly owns the Hydraska Hydro Facility and the Arthurville Hydro Facility, and owns both the limited partnership interests in and the general partner of Algonquin Power (Campbellford) Limited Partnership, an Ontario limited partnership which operates a 4 megawatt hydroelectric generating facility on the Trent River near Campbellford, Ontario (the "**Campbellford Hydro Facility**").

APT also controls the entities which own APUC's interests in two wind projects in Quebec. APT owns a 24.995% interest in Éoliennes Belle-Rivières, sociètè en commandite ("**Val-Eo Partnership**") which owns the Val-Eo Wind Project. A non-Algonquin entity, Val-Eo Coop de solidarité, owns 74.995% of the Val-Eo Partnership. The remaining 0.01% interest in the Val-Eo Partnership is owned by a Quebec numbered company, 9231-5498 Quebec Inc., the general partner. The interests in 9231-5498 Quebec Inc. are owned 75% by Val-Eo Coop de solidarité, and 25% by APT. APT indirectly owns and controls 50% of Saint-Damase Wind Energy Fleur de Lis General Partner Corporation ("**Saint-Damase GP**") which owns the Saint-Damase Wind Project. The remaining 50% is owned by Corporation Municipal de St. Damase, a non-Algonquin entity, which also owns 100% of the preferred shares issued by Saint-Damase GP.

APOT Group

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

APOT controls the entities that own the 104 MW wind facility located at St. Leon, Manitoba (the "**St. Leon Wind Facility**"). The APOT entity that owns the St. Leon Wind Facility is St. Leon Wind Energy LP, an Ontario partnership ("**St. Leon LP**"). St. Leon LP is owned by its general partner, St. Leon Wind Energy GP Inc. ("**St. Leon GP**"), by St. Leon Wind Energy Trust, a Manitoba trust ("**St. Leon Trust**") and by AirSource Power Fund I LP, a Manitoba limited partnership ("**AirSource**"). St. Leon LP has also issued 100 Class B limited partnership units which were acquired by APUC on January 1, 2013 in exchange for newly issued APUC Series C Preferred Shares. St. Leon Trust is owned 100% by AirSource, the limited partner of which is Algonquin (AirSource) Power LP ("**AAP LP**") which holds a 99.99% limited partnership interest in the limited partnership, and which in turn is owned 99.99% by APOT as limited partner. APOT also controls the general partner of AAP LP, AirSource Power Fund GP Inc, a Canadian corporation which holds the remaining 0.01% general partnership interest. AirSource is also the 100% owner of St. Leon GP. St. Leon GP is a Canadian corporation and St. Leon Trust is a trust created by a declaration of trust dated June 28, 2005 in accordance with the laws of the Province of Manitoba. The AirSource and AAP LP limited partnerships were formed in Manitoba and Ontario, respectively.

St. Leon LP directly owns a 99% limited partnership interest in St. Leon II Wind Energy LP ("**St. Leon II LP**"), a Manitoba partnership which owns the 16.5 MW wind facility (the "**St. Leon II Wind Facility**"), an expansion of the St. Leon Wind Facility, located at St. Leon Manitoba. St. Leon LP also wholly owns St. Leon II Wind Energy GP Inc., a Manitoba corporation which owns the remaining 1% general partnership interest in St. Leon II LP.

APOT is the sole limited partner, holding a 99% limited partnership interest, in Red Lily Wind Power II Limited Partnership ("**Red Lily II LP**"), a Saskatchewan limited partnership. The general partner of Red Lily II LP is Red Lily Wind Power II GP Inc., a Saskatchewan corporation, which is also owned by APOT and owns the remaining 1% general partnership interest.

APOT has two ownership interests in Alberta. It is the beneficial owner of one hydroelectric facility in Alberta (the "**Dickson Dam Hydro Facility**"). APOT also owns 50% of Valley Power Corp., an Ontario corporation, which holds a 0.001% limited partnership interest partner in Valley Power LP, an Alberta limited partnership which owns the Alberta biomass facility ("**Valley Power Thermal Facility**") and APOT directly holds a 49.9995% limited partnership interest in Valley Power LP.

APCH Group

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

In Ontario, APCH directly owns the Burgess and Hurdman Hydro Facilities. In Québec, APFC directly owns the facilities known as the Rawdon, Hydro Snemo, St. Raphael, Belleterre, and St. Brigette Hydro Facilities, in addition to owning 100% of the beneficial interest in the St. Alban Hydro Facility. APCH also holds a direct interest in Société Hydro-Donnacona (the "**S.E.N.C.**"), the owner of the Donnacona Hydro Facility. S.E.N.C. is a Québec general partnership, and is owned 99.99% by APCH and 0.01% by Donnacona Holdings Inc., an Ontario corporation 100% owned by APFC. APCH also owns 100% of Algonquin Power Services Canada Inc., a Canadian corporation that provides purchasing services to Canadian APCo entities.

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

APCH also owns Algonquin Power Corporation Inc. ("**APCI**"), an Ontario corporation. APCI owns a 99.9% general partnership interest in Algonquin Power (Long Sault) Partnership (the "**LS Partnership**"), an Ontario general partnership which is a 50% partner in the Long Sault Hydro Facility with the remaining 50% being held by non-Algonquin interests. APCH has an agreement in place which allows it to buy an ownership interest in the parties which own the remaining 50% of the Long Sault project. APCI also 100% owns Algonquin Power (Long Sault) Corporation Inc., an Ontario corporation which is the general partner, holding the remaining 0.1% general partnership interest, in the LS Partnership.

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

APFA Group

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

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

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

APFA owns a 99% equity interest in Wind Portfolio SponsorCo LLC ("**WP SponsorCo**"), a Delaware LLC; the remaining 1% interest is held by Algonquin Power Fund (America) Holdco Inc., a Delaware corporation which is 100% owner by APFA. WP SponsorCo owns 100% of the Class B managing interests in Wind Portfolio Holdings, LLC ("**WP HoldCo**"), a Delaware LLC. Non-APUC partners, JPM Capital Corporation, Morgan Stanley Wind LLC, and Gear Wind LLC, collectively hold 100% of the non-managing Class A interest in WP HoldCo, which in turn owns Wind Energy Portfolio Holdings I, LLC ("**WE HoldCo**"), a Delaware LLC. WE HoldCo directly owns three entities which each own separate wind projects in the USA ("**U.S. Wind Portfolio Facilities**"): Sandy Ridge Wind, LLC, a Delaware LLC, owns the Sandy Ridge Wind Facility in Pennsylvania; Minonk Wind, LLC, a Delaware LLC, owns the Minonk Wind Facility in Illinois; and Senate Wind, LLC, a Delaware LLC, owns the Senate Wind Facility in Texas.

APFA owns Shady Oaks Holdings, LLC, a Delaware LLC, which owns TianRun Shady Oaks, LLC, a Delaware LLC, which owns GSG6, LLC, a Delaware LLC, which owns the Shady Oaks Wind Facility in Illinois.

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

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

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

(ii) Distribution Business Group

Distribution Business Group's Electric, Natural Gas, Water, and Wastewater Utilities

Liberty Utilities owns Liberty Utilities (CalPeco Electric), LLC, a California limited liability company ("**CalPeco**"). CalPeco owns an electricity distribution utility in the Lake Tahoe basin and surrounding areas in California ("**CalPeco Electric System**").

Liberty Utilities owns Liberty Utilities (Midstates Natural Gas) Corp. ("**Liberty Midstates**"), a Missouri corporation. Liberty Midstates owns natural gas distribution utility assets in Missouri, Iowa and Illinois (the "**Midstates Gas Systems**").

Liberty Utilities owns Liberty Energy Utilities (New Hampshire) Corp. ("**Liberty Energy (NH)**"), a Delaware corporation registered to do business in New Hampshire. Liberty Energy Utilities (NH) owns Liberty Utilities (Granite State Electric) Corp., which owns an electrical distribution utility in New Hampshire (the "**Granite State Electric System**") and Liberty Utilities (EnergyNorth Natural Gas) Corp., which owns a natural gas distribution utility in New Hampshire (the "**EnergyNorth Gas System**").

Liberty Utilities owns Liberty Utilities (Peach State Natural Gas) Corp., a Georgia corporation ("**Peach State**"). Peach State owns natural gas distribution utility assets in Georgia (the "**Peach State Gas System**"), which were acquired on April 1, 2013.

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

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

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

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

Liberty Utilities (Sub) Corp.

Liberty Utilities owns Liberty Utilities (Sub) Corp. ("**Liberty SubCo**"), which is a Delaware company. With the exception of the Pine Bluff Water System and the White Hall Water and Waste Systems, Liberty SubCo is the parent company of the water and wastewater entities.

Liberty SubCo owns, through subsidiaries, the water and wastewater businesses located in Arizona, Texas, Missouri, Arkansas and Illinois. Most of these 100% wholly-owned subsidiaries (except Liberty Utilities (Northwest Sewer) Corp. (the "**Northwest Sewer**"), are currently conducting business as "Liberty Utilities"; however the actual legal names of the relevant entities are set out below.

In Arizona, the following Arizona corporations own the following facilities: Liberty Utilities (Bella Vista Water) Corp. owns the Bella Vista Water System; Liberty Utilities (Black Mountain Sewer) Corp. owns the Black Mountain Waste System; Liberty Utilities (Gold Canyon Sewer) Corp. owns the Gold Canyon Waste System; Liberty Utilities (Litchfield Park Water & Sewer) Corp. owns the Litchfield Waste & Water Systems; Liberty Utilities (Northern Sunrise Water) Corp. owns the Northern Sunrise Water System; Liberty Utilities (Rio Rico Water & Sewer) Corp. owns the Rio Rico Water & Waste Systems; Liberty Utilities (Entrada Del Oro Sewer) Corp. owns the Entrada Del Oro Waste System; and Liberty Utilities (Southern Sunrise Water) Corp. owns the Southern Sunrise Water System.

In Texas, the following Texas corporations own the following facilities: Liberty Utilities (Tall Timbers Sewer) Corp. owns the Tall Timbers Waste System; Liberty Utilities (Woodmark Sewer) Corp. owns the Woodmark Waste System; Liberty Utilities (Silverleaf Water), LLC, a Texas limited liability company, owns water and wastewater treatment assets at the Holly Lake Ranch, Hill County, Piney Shores and The Villages (also known as "Big Eddy") Resorts; and Liberty Utilities (Seaside Water), LLC., a Texas limited liability company, owns water and wastewater treatment assets at the Seaside Resort.

In Missouri, Liberty Utilities (Missouri Water), LLC, a Missouri limited liability company, owns assets associated with the Holiday Hills, Ozark Mountain, Timbercreek resorts, the water utility in Noel, Missouri and a utility in eastern Missouri. In Illinois, Liberty Utilities (Fox River Water), LLC, an Illinois limited liability company, owns assets serving the Fox River Resort.

(iii) Transmission Business Group

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

(iv) Other

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

APUC also has ownership interests in a group of special purpose financing companies, including 90% of Liberty Utilities Finance GP 1 ("**LU GP1**"), a Delaware general partnership. LU GP1 owns 99.9% of Liberty Utilities Finance GP 2 ("**LU GP2**"), a Delaware general partnership. The minority partner in both LU GP1 and LU GP2 is 3793257. LU GP2 owns Liberty Utilities Finance (Canada) ULC, an Alberta unlimited liability corporation which in turn owns Liberty Utilities Finance (US) LLC, a Delaware limited liability company. The above entities were formed as special purpose financing entities used in Liberty Utilities financings.

LU Canada owns one special purpose financing company, Liberty Utilities (U.S. Pref) Holdco Corp., an Ontario corporation. In 2014, LU Canada created a limited partnership for purposes of holding a corporate office location. LU Canada owns 99.99% of Davis Road LP, an Ontario limited partnership, and it also owns 100% of Davis Road GP Inc., the general partner and 0.01% owner of Davis Road LP.

1.2.2 Other Interests in Energy Related Developments

The Corporation also has notes receivable and equity in companies owning generating facilities as described below. APT owns 25% of the Class B non-voting shares issued by Cochrane Power Corporation, the owner of a combined cycle cogeneration facility located in Cochrane, Ontario. APT also owns 32.4% of the Class B non-voting shares in Kirkland Lake Power Corporation, an entity which burns natural gas and wood waste to generate electricity. APT also owns a 12.1% interest in Tranche A term loan issued by Chapais Energie, Société en Commandite ("**Chapais**") which owns a wood waste facility in Chapais, Québec. It also owns a 33.9% interest in the Class B non-voting preferred shares of Chapais. The term loan bear an interest rate of 10.789%.

In addition, APCo is entitled to a royalty in the form of cash flows generated by the Long Sault Hydro Facility (the "**LSR Royalty Interest**"). It is also the owner of a 14.14% secured, subordinated note (the "**LSR Subordinate Note**") in the principal amount of $2,000,000 issued jointly and severally by Algonquin Power (Long Sault) Corporation Inc., Energy Acquisition (Long Sault) Ltd., Nicholls Holdings Inc. and Radtke Holdings Inc.

As of January 1, 2013, APUC owns the Class B limited partnership units of St. Leon Wind Energy LP, the legal owner of the St. Leon Wind Facility.

2. GENERAL DEVELOPMENT OF THE BUSINESS

2.1 General

2.1.1 Business Strategy

APUC owns and operates a diversified portfolio of regulated and non-regulated generation, distribution and transmission utility assets which deliver predictable earnings and cash flows. APUC seeks to maximize total shareholder value through a quarterly dividend augmented by share price appreciation arising from dividend growth supported by increasing per share cash flows and earnings.

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

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

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

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

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

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

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

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

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

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

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

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

2.2 Three Year History and Significant Acquisitions

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

2.2.1 Fiscal 2012

Corporate

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

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

(ii) Issuance of $120M of Preferred Shares

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

(iii) Private Placements to Emera

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

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

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

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

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

(vi) Corporate Credit Facility

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

Generation Group

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

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

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

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

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

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

(ii) $150 million Senior Unsecured Debentures

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

(iii) Generation Credit Facility

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

(iv) Completion of Windsor Locks Thermal Facility Repowering

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

Distribution Group

(i) Acquisition of Remaining Interest in CalPeco Electric System

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

(ii) Acquisition of New Hampshire Utilities

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

(iii) Acquisition of Midstates Gas System

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

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

(iv) U.S. Debt Private Placements

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

(v) Expansion of Distribution Credit Facility

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

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

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

2.2.2 Fiscal 2013

Corporate

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

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

(ii) Credit Rating Upgrade

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

(iii) Related Party Transactions

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

(iv) Emera Subscription Receipts

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

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

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

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

(vi) Expansion of the Corporate Credit Facility

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

Generation Group

(i) Acquisition of the 20 MWac Bakersfield Solar Project

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

(ii) Acquisition of Shady Oaks Wind Facility

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

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

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

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

(iii) Energy From Waste Facility

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

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

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

Distribution Group

(i) Acquisition of the New England Gas System

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

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

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

(ii) Acquisition of the Peach State Gas System

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

(iii) Acquisition of the Pine Bluff Water System

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

(iv) U.S. Debt Private Placements

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

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

(v) Expansion of the Distribution Credit Facility

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

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

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

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

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

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

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

2.2.3 Fiscal 2014

Corporate

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

In 2014 the company successfully advanced various initiatives raising the growth profile for earnings and cash flows which in turn supported an increase in the dividend to shareholders. As a result, on August 14, 2014, the Board approved a dividend increase to U.S. $0.35 per share per annum, paid quarterly at a rate of U.S. $0.0875 per share, a 12.4% increase over the previous dividend of CDN $0.34 calculated using the exchange rate in effect at that time. The change in the currency of the dividend better aligns APUC's dividend with the currency profile of its underlying operations. In 2014, APUC's consolidated assets are approximately 80% based in the U.S. and generate approximately 77% of its underlying cash flows.

(ii) Issuance of $100 million Preferred Shares

On March 5, 2014, APUC issued 4.0 million cumulative rate reset preferred shares, Series D (the "**Series D shares**") at a price of $25 per share, for aggregate gross proceeds of $100.0 million. The Series D shares yield 5.0% annually for the initial five-year period ending March 31, 2019. The preferred shares have been assigned a rating of P-3 (High) and Pfd-3 (Low) by S&P and DBRS, respectively. The net proceeds of the offering were used to partially finance certain of APUC's previously disclosed growth opportunities, reduce amounts outstanding on APUC's credit facilities, and for general corporate purposes.

(iii) Issuance of Common Shares

On September 16, 2014, APUC completed a public offering (the "**September Offering**") of 16,860,000 common shares at a price of $8.90 per share, for gross proceeds of approximately $150.0 million. On September 26, 2014, the underwriters exercised the over-allotment option granted with the September Offering and an additional 2,529,000 common shares were issued on the same terms and conditions of the September Offering. As a result, APUC issued an aggregate of 19,389,000 common shares under the Offering for the total gross proceeds of approximately $172.6 million.

On December 11, 2014, APUC completed a public offering of 10,055,000 common shares at a price of $9.95 per share, for gross proceeds of approximately $100.0 million.

Net proceeds of both common share offerings were used to finance certain of APUC's previously disclosed growth opportunities, reduce amounts outstanding on APUC's credit facilities, and for general corporate purposes.

(iv) Private Placement of Subscription Receipts to Emera Inc.

On September 4, 2014, APUC and Emera entered into a subscription agreement pursuant to which Emera agreed to subscribe for an aggregate of 7,865,170 subscription receipts ("**Subscription Receipts**") of APUC at a price of $8.90 per Subscription Receipt, for an aggregate subscription amount of $70.0 million.

On September 26, 2014, as a result of the Underwriters exercising the Over-Allotment Option, an additional 843,000 Subscription Receipts were issued to Emera at a price of $8.90 per Subscription Receipt, for an aggregate subscription amount of $77.5 million.

On December 2, 2014, APUC and Emera entered into an additional subscription agreement to which Emera agreed to subscribe for an aggregate of 3,316,583 Subscription Receipts at a price of $9.95 per Subscription Receipt, for an aggregate subscription amount of $33.0 million.

The proceeds of the Subscription Receipts private placements are intended to be used to partially finance the acquisitions of the Odell Wind Project and the Park Water Facility.

Generation Group

(i) Acquisition of Odell Wind Project

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

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

(ii) Completion of Cornwall Solar Project

During the quarter ended March 31, 2014, the Generation Group completed the construction of its 10 MWac solar project located near Cornwall, Ontario. The facility reached commercial operation on March 27, 2014 for a total capital cost of approximately $47.6 million. The facility represents the first solar project in the Generation Group's portfolio. The facility is expected to generate approximately 14,400 MW-hrs of electricity annually with the power sold under a 20 year FIT contract with the Independent Electricity System Operator ("**IESO**"), formerly the Ontario Power Authority ("**OPA**").

(iii) Completion of St. Damase Wind Project

On December 2, 2014, the first phase of the wind facility located in the local municipality of Saint-Damase reached commercial operations. The 24 MW facility is expected to generate 76,900 MW-hrs of electricity annually with the power sold under a 20 year PPA with Hydro Quebec.

It is expected that the turbines and other components utilized in the first 24 MW phase of the Saint-Damase Wind Project will qualify as Canadian Renewable and Conservation Expense ("**CRCE**"), and therefore a significant portion of the Phase I capital cost will be eligible for a refundable Quebec tax credit ("**Quebec CRCE Tax Credit**"). The estimated value of the Quebec CRCE tax credit for the Saint-Damase project is expected to be approximately $16.6 million. Phase II of the project will be constructed following evaluation of the wind resource at the site, completion of satisfactory permitting, and entering into appropriate energy sales arrangements.

(iv) Expansion of Bakersfield I Solar Project

On November 24, 2014, APUC announced that it intends to proceed with a 10 MW project adjacent to its 20MW Bakersfield I Solar project in Kern County, California, which is currently under construction.

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

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

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

On March 31, 2014, the Generation Group acquired from Gamesa Wind US, LLC ("**Gamesa**") the remaining 40% of the Class B partnership units of the entity which owns a three facility 400 MW U.S. Wind Portfolio in the United States for total consideration of approximately U.S. $115.0 million. As a result of the transaction, the Generation Group now owns 100% of the Class B partnership units of the entity that owns the U.S. Wind Portfolio. Gamesa will continue to provide operations, warranty and maintenance services for the wind turbines and balance of plant facilities under 20 year contracts. The acquisition was funded primarily from the proceeds from the $200.0 million of debentures issued by the Generation Group early in 2014 as discussed below.

(vi) $200 million Senior Unsecured Debentures

On January 17, 2014, the Generation Group issued $200.0 million 4.65% senior unsecured debentures with a maturity date of February 15, 2022 (the "2014 Generation Group Debentures") pursuant to a private placement in Canada and the United States. The 2014 Generation Group Debentures were sold at a price of $99.864 per $100.00 principal amount resulting in an effective yield of 4.67%. Concurrent with the offering, the Generation Group entered into a fixed for fixed cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated debentures into U.S. dollars, resulting in an effective interest rate throughout the term of approximately 4.77%.

Net proceeds were used towards financing the acquisition of the remaining 40% ownership interest in its U.S. Wind Portfolio, to reduce amounts outstanding on project debt related to its Shady Oaks Wind Facility, to reduce amounts outstanding under its bank credit facility, and for general corporate purposes.

(vii) Additional Liquidity

On July 31, 2014, the Generation Group increased the credit available under the senior unsecured credit facility (the "Generation Group Credit Facility") to $350.0 million from $200.0 million. The larger credit facility provides additional liquidity in support of the group's $1,225.0 million development portfolio to be completed over the next three years. In addition to the larger size, the maturity of the facility has been extended from three to four years and now extends until July 31, 2018

Distribution Group

(i) Agreement to acquire Park Water System

On September 19, 2014, the Distribution Group announced the entering into an agreement with Western Water Holdings, a wholly-owned investment of Carlyle Infrastructure, to acquire the regulated water distribution utility Park Water Company ("**Park Water System**"). Park Water System owns and operates three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in Southern California and Western Montana. The three utilities collectively serve approximately 74,000 customer connections and have more than 1,000 miles of distribution mains.

Total consideration for the utility purchase is expected to be approximately U.S. $327.0 million, which includes the assumption of approximately U.S. $77.0 million of existing long-term utility debt. The acquisition will maintain APUC's strategic business mix and further enhance its investment grade consolidated capital structure.

(ii) Acquisition of White Hall Water System

On May 30, 2014, the Distribution Group acquired the assets of the White Hall Water System, a regulated water distribution and wastewater treatment utility located in White Hall, Arkansas. The White Hall Water System serves approximately 1,900 water distribution and 2,400 wastewater treatment customers. Total purchase price for the White Hall Water System assets, adjusted for certain working capital and other closing adjustments, is approximately U.S. $4.5 million.

(iii) Successful Completion of the Granite State Electric System Rate Case

In the first quarter of 2013, the Granite State Electric System filed a rate case with the New Hampshire Public Utilities Commission ("**NHPUC**") seeking an increase in rates of U.S. $13.0 million, and an additional U.S. $1.2 million increase in 2014 subject to the completion of certain capital projects. On March 17, 2014, the commission approved a settlement of U.S. $9.8 million and U.S. $1.1 million step increase for 2014.

(iv) Successful Completion of the Peach State Gas System GRAM Filings

On October 1, 2013, the Peach State Gas System filed an application for an increase in revenue of U.S. $4.9 million in its annual GRAM filing with the GPSC. In January 2014, the Distribution Group and the Staff of the GPSC agreed to a settlement which will provide an annual revenue increase of U.S. $3.2 million, and the recovery of U.S. $1.7 million of carrying charges on deferred rate base in a future GRAM filing. Commission approval was received in May 2014, with new rates effective as of June 1, 2014.

On October 1, 2014, the Peach State Gas System filed an application for an increase in revenue of U.S. $3.7 million in its annual GRAM filing with the GPSC. New rates to be effective February 1, 2015 for the period February 1, 2015, through January 31, 2016 were to reflect changes in revenue levels and cost of service. The GRAM uses a 12 month base period ending June 30, 2014 (Historic Test Year) with adjustments for the 12 months ending August 31, 2015 (Forward Looking Test Year). Commission approval was received on December 4, 2014.

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

On February 28, 2013, LPSCo Water System filed a general rate case with the Arizona Corporation Commission related to the LPSCo Water System sought, among other things, an increase in EBITDA by U.S. $3.0 million over the 2012 results if approved as filed. The application sought recognition of increased capital investment and increased operating expenses over current rates. In addition to a revenue increase, the application sought an accelerated infrastructure recovery surcharge, a purchased power pass-through mechanism to recover power price increases between test years, a property tax accounting deferral to defer increases in property taxes between test years, and a policy statement on rate design to begin the gradual shift of moving more revenue recovery to fixed charges versus commodity charges. In April 2014 the commission approved a $1.8 million increase in rates effective on May 1, 2014.

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

On February 6, 2014, the Midstates Gas System filed a rate case with the Missouri Public Service Commission ("**MPSC**") seeking an increase in revenue of U.S. $7.6 million, consisting of U.S. $6.3 million in new, incremental revenue and U.S. $1.3 million through the ISRS surcharge (infrastructure system replacement surcharge). The filing is based on a test year ending September 30, 2013, with revenues, expenses and rate bases adjusted to reflect known and measurable changes

through April 30, 2014. The case has concluded and an Order was issued on December 3, 2014, approving a U.S. $4.9 million revenue increase effective January 2, 2015.

(vii) Pine Bluff Water System Rate Case Proceedings

On July 2, 2014, Pine Bluff Water System filed an application with the Arkansas Public Service Commission ("**APSC**") seeking an increase in revenue of U.S. $2.5 million based on a test year ending January 31, 2014, with pro forma changes to certain operating expenses and rate base capital additions. The previous test year ended September 30, 2009. An Order and new rates are expected in the second quarter of 2015.

(viii) EnergyNorth Gas System Rate Case Proceedings

On August 1, 2014, the EnergyNorth Natural Gas System in New Hampshire filed an application for an increase in revenue of U.S. $16.1 million, or approximately 9.6%. The application includes a revenue decoupling proposal and seeks recovery of capital costs related to the conversion of the system to the Distribution Group ownership. Expected implementation of the new permanent rates is in the third quarter of 2015. A temporary rate increase was approved on November 21, 2014 allowing a U.S. $7.4 million interim rate increase effective December 1, 2014, retroactive to November 2014 upon approval of permanent rates.

Transmission Group

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

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

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

2.3 Recent Developments - 2015

Corporate

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

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

Generation Group

(i) Completion of Morse Wind Project

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

(ii) Completion of Bakersfield I Solar Project

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

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

Distribution Group

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

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

3. DESCRIPTION OF THE BUSINESS

3.1 Generation Group

3.1.1 Regulatory Regimes - Power Generation

(i) Canada

The electricity supplied within the Canadian provinces is primarily generated by government-owned corporations, such as Ontario Power Generation Inc. and Hydro-Québec. Independent power producers, such as APUC provide additional capacity and supply to the grids. In Canada, the provinces have legislative authority over the generation, transmission and distribution of electricity. This in turn means that each province may have different requirements for the business to comply with in respect of the projects it owns in each province.

Generally speaking, each province in which the company operates has various pieces of legislation in effect which the business must comply with. These relate to the generation, transmission and distribution of electricity in the province, the administration of the electric system, as well as the creation and authority of various governmental agencies who have oversight of an aspect of the industry, such as the independent system operator and the provincial energy board, utilities commission or other similar authority responsible for rate-making and regulatory oversight of the industry. In addition, some provinces require a generator of electricity to be licensed and registered with the appropriate governmental authority and the company must comply with the conditions of license or registration accordingly. In addition to the legal requirements, the system operators have promulgated market rules to be complied with within their operating jurisdictions and any codes, rules and standards of the applicable energy board or utilities commission must be complied with.

(ii) United States

The power generation industry in the United States is regulated by the United States FERC under the U.S. Federal Power Act ("**FPA**"), Public Utilities Regulatory Policies Act ("**PURPA**") and the Public Utility Holding Company Act of 2005 ("**PUHCA**").

(1) Rate Regulation

All of APUC's operating US power generation facilities are either: (1) exempt wholesale generators ("**EWGs**"); or (2) qualifying small power or cogeneration facilities ("**QFs**"). EWGs sell electricity exclusively in wholesale markets, while QFs with a power production capacity of 20 MW or less are exempt from most regulation under the FPA. There are two types of QFs: (1) qualifying small power production facilities; and (2) qualifying cogeneration facilities. In order to be a qualifying small power production facility, which includes hydro, geothermal, solar and biomass, the facility must meet the maximum size and fuel use criteria specified in FERC's regulations. In order to be a qualifying cogeneration facility, the facility must meet the operating and efficiency criteria specified in FERC's regulations. All APUC's operating US power generation facilities that are EWGs possess FERC authorization to engage for sales for resale at market-based rates ("**MBR Authority**"). The QF with a capacity greater than 20 MW also possesses MBR Authority. QFs with a capacity of 20 MW or less are not required to possess MBR Authority for their power sales. MBR Authority is available to EWGs and certain QFs and is obtained by showing that the generator and its affiliates do not possess vertical or horizontal market power in the relevant market. Once MBR Authority is obtained, the EWG or QF with a capacity greater than 20 MW, may sell its power into the relevant market at market-based rates. Each entity with MBR Authority must detail its sales into the market by filing quarterly reports which details the relevant contracts used to sell power and the rates obtained for such power sales. QFs with a capacity of 20 MW or less are not required to file quarterly reports.

(2) PUHCA

APUC is also subject to the PUHCA. PUHCA and FERC's implementing regulations impose certain books, records and accounting requirements on public utility holding companies. APUC is a public utility holding company and subject to such

regulations. The Generation Group's intermediate holding companies claims exemption from PUCHA under 18 CFR Section 366.3, which provides that a company that is a holding company solely by virtue of holding interests in QFs, EWGs and foreign utility companies is exempt from the books, records and accounting provisions of PUHCA and FERC's regulations. Should any of the EWGs or QFs cease qualifying for such status by no longer meeting the regulatory requirements for qualification, then the exemption would no longer apply. At that time, the books, records and accounting requirements, requiring use of the Uniform System of Accounts would then apply.

3.1.2 Description of Operations

Hydroelectric Generating Facilities

(i) Production Method

A hydroelectric generating facility consists of a number of components, including a dam, headrace canal or penstock, intake structure, electromechanical equipment consisting of a turbine(s), a generator(s), draft tube and tailrace canal. In addition, there are electrical switchgear and controls equipment which are necessary to interconnect the facility with the receiving electrical grid system.

A dam structure is required to create or increase the natural elevation difference between the upstream reservoir and the downstream tailrace (referred to as "**head**"), as well as to provide sufficient depth within the reservoir for an intake. Dam structures are also used to create an upstream reservoir which allows water to be stored within a head pond.

Water flows are conveyed from the upstream reservoir to the generating equipment via a penstock or headrace canal. A penstock is a pipeline capable of operating under pressure, and is normally constructed of steel or other suitable materials. A headrace canal is a channel which conveys water from the reservoir to the intake in a hydraulically efficient manner. The intake structure is a water intake located at the entrance to a penstock or at the end of a headrace canal. The purpose of the intake structure is to collect water from the upstream reservoir. Turbine(s) and generator(s) transform the hydraulic energy into electrical energy.

The water which has flowed through the hydraulic turbine(s) is discharged back to the natural watercourse. A transmission line is often required to interconnect a facility with the grid. The majority of hydroelectric generating facilities are also equipped with remote monitoring equipment, which allows the facility to be monitored and operated from a remote location.

(ii) Principal Markets and Distribution Methods

The principal markets in which APUC operates in Canada are Alberta, Ontario, New Brunswick and Québec. In the US, the principal market is Maine. The majority of generated hydroelectricity is conveyed from the relevant facility to the purchasers under the terms of long term PPAs. The electricity is generally transferred by transmission line from the generating facility to the delivery point for the purchaser, and it is distributed through the grid to end user customers of the purchaser. A summary of the PPAs for the Generation Group's Renewable Energy division is set out in Schedule A.

(1) Alberta

The electrical power industry in Alberta is regulated by the Electric Utilities Act (Alberta) ("**EUA**"). The Power Pool of Alberta ("**Power Pool**") was established under the EUA to provide a competitive, real-time spot market for electric energy. The Power Pool is non-discriminatory and open to any generator, marketer, distributor, importer or exporter that satisfies the qualification requirements established under the EUA and the rules and codes of practice of the Power Pool.

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

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

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

(2) Ontario

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

The Ontario Electricity Financial Corporation holds all rights, obligations and liabilities under, and purchases the energy generated by the Ontario facilities in which APUC has an interest pursuant to, the existing contracts. APUC's relevant subsidiary entities have also received a license to generate from the OEB as required by the *Ontario Energy Board Act, 1998* (Ontario).

(3) New Brunswick and Northern Maine

Effective October 1, 2013, the New Brunswick government amended the provincial Electricity Act (New Brunswick), which resulted in the re-amalgamation of the New Brunswick System Operator ("**NBSO**") with members of the New Brunswick Power Corporation ("**NB Power**"), a vertically-integrated group of companies, resulting in the transmission system operation functions of the NBSO being performed by NB Power's Transmission and System Operator division.

(4) Québec

Hydro-Québec is the primary electricity generator, transmitter, and distributor of electricity in the province of Québec; its sole shareholder is the Québec government. It uses mainly renewable generating options, in particular large hydro, and supports the development of other technologies-such as wind energy and biomass.

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

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

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

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

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

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

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

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

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

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

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

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

(iii) Material Facilities

(1) Long Sault Hydro Facility

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

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

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

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

PPA

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

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

Waterpower Lease

The waterpower lease with the Province of Ontario in respect of the dam site expires in 2048. The lease provides for an annual land rental and an annual water rental charge. The annual water rental charge commenced in January 2008.

Co-Owners Agreement and Management Agreement

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

Credit Agreement

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

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

Residual Ownership Interest

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

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

(2) Côte Ste-Catherine Hydro Facility

The Côte Ste-Catherine Hydro Facility is a hydroelectric generating facility located at the Côte Ste-Catherine lock of the Lachine section of the St. Lawrence Seaway. The bypass canal upon which the facility is located was constructed as part of the St. Lawrence Seaway in 1958. The facility has a total installed capacity of 11.1 MW. The facility is owned by the Mont-Laurier Partnership.

The land and water rights necessary for the operation of the facility have been obtained from the St. Lawrence Seaway Authority by way of a lease agreement with the Province of Québec. In 2009, the water rights lease was renewed for a term of 21 years commencing March 1, 2009. Although the facility is located on a federal waterway, the Province of Quebec has asserted jurisdiction over the water rights to this facility and has also asserted a claim against a predecessor by amalgamation to APCH for payment of revenues paid to the federal authority. See "*Risk Factors - Operational Risks Management - Litigation Risks and Other Contingencies*".

(3) Mont Laurier Hydro Facility

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

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

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

Each of the Côte Ste-Catherine and Mont Laurier Hydro Facilities has a PPA with Hydro-Québec under which all power generated by the facilities is sold to Hydro-Québec. The standard Hydro-Québec PPA stipulates annual minimum energy production requirements in each contract year. Under most Hydro-Québec PPAs, if a facility produces less energy than the minimum, a penalty is payable to Hydro-Québec. The facility can opt to reduce any energy production shortfall over a two year period using energy produced in excess of the minimum requirement, after which, a penalty is payable on any outstanding amounts at the current year prices.

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

(5) Tinker Hydro Facility

The Tinker hydro facility (the "**Tinker Hydro Facility**") is located 5 miles north of Perth-Andover, New Brunswick and is situated near the mouth of the Aroostook River. The facility consists of five hydro units and a 1 MW diesel generator; the total nameplate capacity of the station equals 38.9 MW. Historical gross generation from the station averages 140,000 MW-hrs per year. The Tinker Hydro Facility benefits from the flow regulation of the Millinocket Dam and Squa Pan hydro facilities, both of which are also owned and operated by APCo.

As part of the generation assets in New Brunswick and Northern Maine, APUC owns an electrical transmission system consisting of 14.7 km of 69 kV transmission line facilities. These facilities are used to interconnect the Tinker Hydro Facility to the New Brunswick transmission network, provide transmission service to Perth Andover Electric Light Commission, and provide export/ import capacity between Maine and New Brunswick.

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

Energy Marketing

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

The Energy Marketing Group purchases additional energy and applicable environmental attributes from the market to supplement the purchases from the Tinker Hydro Facility in order to service its customer demand, and sells any excess generation to the market. Risk associated with this business is managed through the purchase of fixed volume/prices from the market. In addition, the Energy Marketing Group negotiates appropriate pricing with large retail and wholesale consumers in northern Maine to ensure risk associated with volatility of consumption by the consumer is mitigated.

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

(6) Dickson Dam Hydro Facility

The Dickson Dam Hydro Facility is located 20 kilometers west of the Town of Innisfail, Alberta. The facility is a 15.0 MW hydroelectric generating facility utilizing the infrastructure located at the Dickson Dam and powered by the water flows of the Red Deer River. The facility consists of three horizontal Francis type turbines and was commissioned into commercial operation on January 16, 1992. The facility is owned by APOT.

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

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

Wind Power Generating Facilities

(i) Production Method

The energy of the wind can be harnessed for the production of electricity through the use of wind turbines. A wind energy system transforms the kinetic energy of wind into electrical energy that can be delivered to the electricity distribution system for use by energy consumers. When the wind blows, large rotor blades on the wind turbines are rotated, generating energy that is converted to electricity. Most modern wind turbines consist of a rotor mounted on a shaft connected to a speed increasing gear box and high speed generator. Monitoring systems control the angle of and power output from the rotor blades to ensure that the rotor blades are turned to face the wind direction, and generally to monitor the wind turbines installed at a facility.

(ii) Principal Markets and Distribution Methods

The principal markets for APUC's operational wind facilities in Canada are Manitoba for the St. Leon Wind Facilities, Saskatchewan for the Red Lily I Wind Facility, and Quebec for the St. Damase Wind Facility. The electricity generated by the wind turbines is transmitted via electrical collection lines to the facility substations for subsequent delivery to the transmission system of the purchaser, Manitoba Hydro-Electric Board ("**Manitoba Hydro**") in the case of the St. Leon Wind Facilities, Saskatchewan Power Corporation ("**SaskPower**") in the case of the Red Lily I Wind Facility, and Hydro Quebec Distribution ("**Hydro Quebec**") in the case of the St. Damase Wind Facility. The purchaser then distributes the electricity to its customers or to other endpoints via the grid. The principal markets for APUC's wind facilities in the United States are the PJM Interconnection ("**PJM**") and Electric Reliability Council of Texas regional markets ("**ERCOT**").

(1) Manitoba

Historically, Manitoba Hydro had been exclusively responsible for the production of electricity in the province. Manitoba Hydro is a net exporter of electricity, mainly to Ontario and certain states of the United States. To date, the province has been able to utilize its large hydroelectric resources to satisfy internal and export requirements.

(2) Saskatchewan

Saskatchewan's electricity market remains under provincial government control and has not undergone any significant deregulation. SaskPower, the primary electricity utility in Saskatchewan, is wholly-owned by the province through the Crown Investments Corporation. SaskPower anticipates requiring 1,700 MW of additional supply by 2020 and 3,700 MW by 2030 to accommodate load growth and the retirement of generation facilities. As a result, SaskPower has a number of programs to encourage and solicit wind and other renewable power from independent producers.

(3) Quebec

Hydro-Québec's hydroelectric portfolio accounts 99% of electricity mix, and as such, the utility has encouraged the development of wind projects in the province in recent years. Hydro-Québec held wind project calls for tenders in 2005 and 2009 that directly resulted in 2,187 MW of wind capacity to be installed in the province. Additional 450 MW calls for tenders were issued in 2013, seeking energy to be delivered in 2016 or 2017, and in March 2015, seeking 500 MW to be delivered in 2018 or 2019.

(4) Illinois and Pennsylvania

PJM is one of ten regional transmission organizations ("**RTOs**") operating in North America. PJM coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. Acting as a neutral, independent party, PJM operates a competitive wholesale electricity market and manages the high voltage electricity grid to ensure reliability for more than 60 million people.

(5) Minnesota

The Midcontinent Independent System Operator ("**MISO**") is an Independent System Operator ("**ISO**"), similar to an RTO, operating in fifteen U.S. states and the Canadian province of Manitoba. MISO assures consumers of unbiased regional grid management and open access to the transmission facilities through their functional supervision. MISO has interconnections with PJM, ERCOT, and other RTOs and ISOs. The fifteen states where MISO operates are: Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, South Dakota, North Dakota, Texas and Wisconsin.

(6) Texas

ERCOT, like PJM, is one of the ten RTOs operating in North America. ERCOT is the successor to the Texas Interconnect System and its region occupies the entire Texas interconnection which occupies nearly all of the state of Texas. Unlike the other major North American Electric Reliability Corporation interconnections, the high voltage transmission and energy market within the Texas interconnection is operated by ERCOT as essentially a single power system instead of as a network of cooperating utility companies. The portion of the electric grid in the State of Texas that is under the administration of ERCOT was – and remains – essentially unconnected to electrical grids in other states and, in the absence of "electricity in interstate commerce," does not fall under federal regulation. ERCOT is a membership-based, non-profit council that provides electric power to approximately 23 million people in Texas.

(iii) Material Facilities

(1) St. Leon Wind Facility

The St. Leon Wind Facility is a 104 MW wind energy facility located near St. Leon, Manitoba, 150 km southwest of Winnipeg. The facility is owned by St. Leon LP.

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

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

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

(2) St. Leon II Wind Facility

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

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

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

(3) Red Lily Wind Facility

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

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

(4) St. Damase Wind Facility

The St. Damase Wind Facility is a 24 MW wind energy facility located in the MRC of La Matapédia in the Gaspé Region of the Province of Québec, 440 km east northeast of Québec City, Québec.

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

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

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

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

(5) Shady Oaks Wind Facility

The Shady Oaks Wind Facility is a 109.5 MW wind energy facility located in Lee County, Illinois, 80 km west of Chicago. The Shady Oaks Wind Facility is owned by GSG 6, LLC, an entity acquired by APFA from Goldwind on January 1, 2013.

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

GSG 6, LLC has entered into a 20 year power sales contract with the largest electric utility in the state of Illinois, Commonwealth Edison. The power sales contract is structured to hedge the preponderance of the Shady Oaks Wind Facility's production volume against exposure to PJM ComEd Hub current spot market rates. Annual production is subject to contingent curtailment

based on certain regulatory constraints of the electricity purchaser. The remaining generation and associated RECs are sold into the market. The Shady Oaks Wind Facility reached commercial operation in June 2012. Under the terms of the power sales contract, GSG 6, LLC is required to provide security in an amount of US$4.7 million. That obligation is being maintained by Goldwind utilizing an irrevocable letter of credit with an associated fee being assessed to APFA.

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

(6) Sandy Ridge Wind Facility

The Sandy Ridge Wind Facility is a 50 MW wind energy facility located near Tyrone, Pennsylvania, 180 km east of Pittsburgh. The Sandy Ridge Wind Facility is owned by Sandy Ridge Wind, LLC. APFA indirectly owns 100% of the managing ownership interests in Sandy Ridge Wind, LLC through WP SponsorCo.

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

Sandy Ridge Wind, LLC is party to a long term energy production hedge ("**Primary Energy Production Hedge**") with J.P. Morgan Ventures Energy Corporation ("**JPMVEC**"), a wholly owned subsidiary of J.P. Morgan, having a term of 10 years beginning January 1, 2013. Based on the JPMVEC contract quantity, approximately 72% of energy revenues are expected to be earned under an Energy Production Hedge. Ancillary services, including capacity and RECs, are sold into the energy market in which the Sandy Ridge Wind Facility is registered.

(7) Minonk Wind Facility

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

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

Minonk Wind, LLC is party to a Primary Energy Production Hedge with JPMVEC, having a term of 10 years beginning January 1, 2013. Based on the JPMVEC contract quantity, approximately 73% of energy revenues are expected to be earned under an Energy Production Hedge. Ancillary services, including capacity and REC, are sold into the energy market in which the Minonk Wind Facility is registered.

(8) Senate Wind Facility

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

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

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

(iv) Renewable Energy Credits

Renewable Energy Credits ("**RECs**") are tradable commodities representing the generation of 1 MWh of electricity, and are used by utilities to satisfy compliance with Renewable Portfolio Standards ("**RPS**") where necessary. These RPS mandates are set at a state level, and stipulate a certain amount of electricity to be generated from renewable sources by a specific year. These targets range from 10-40%, with some initial deadlines having already passed, and some stretching to 2025 and beyond. At the current time the Minonk, Sandy Ridge, Senate, and Shady Oaks Wind Facilities each produce and sell RECs through bilateral contracts.

Solar Power Generating Facilities

(i) Production Method

Solar power is the conversion of sunlight into electricity, either directly using photovoltaics or indirectly using concentrated solar power. APUC's solar generation facilities, the Cornwall Solar Facility, and the Bakersfield I Solar Facility, utilizes photovoltaics which convert light into electric current using the photovoltaic effect. The array of a photovoltaic power system produces direct current ("**DC**") power which fluctuates with the sunlight's intensity. For practical use, commercial installations convert this DC generated power to alternating current ("**AC**"), through the use of inverters. Multiple solar cells are connected inside modules. Modules are wired together to form arrays, then connected to an inverter, which produces power at the desired voltage/frequency/phase.

(ii) Principal Markets and Distribution Methods

The principal market for APUC's operational solar facility in Canada is Ontario for the Cornwall Solar Facility, and California for the Bakersfield I Solar Facility. The electricity generated by the solar panels is transmitted via electrical collection lines to the facility substation for subsequent delivery to the distribution/transmission system under control of the local distribution company and the independent system operator.

(1) Ontario

The IESO was merged with the OPA in 2015. The combined organization operating as the IESO is an independent, non-profit corporation that is responsible for the real time operation, long term planning and procurement for Ontario's electricity system. The IESO is licensed by the Ontario Energy Board, it reports to the Ontario legislature through Ontario's Ministry of Energy.

(2) California

The California Independent System Operation ("**CAISO**") was formed in 1998 following a restructuring of the state electricity markets, and at the recommendation of the Federal Energy Regulatory Commission ("**FERC**"). The CAISO operates as a nonprofit public corporation responsible for operating the wholesale power system, maintaining the reliability of the grid, and planning for future demands. It is regulated by FERC.

(iii) Material Facilities

(1) Cornwall Solar Facility

The Cornwall Solar Facility is a 10 MW AC ground mounted photovoltaic solar energy facility located near Cornwall, Ontario, 100 km southeast of Ottawa.

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

(2) Bakersfield I Solar Facility

The Bakersfield Solar Facility is a 20 MW AC ground mounted photovoltaic solar energy facility that uses single axis trackers to optimize the site's generating efficiency. The site is located near Bakersfield, California, 150 km northwest of Los Angeles.

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

Thermal (Cogeneration) Electric Generating Facilities

(i) Production Method

Cogeneration is the simultaneous production of electricity and thermal energy such as hot water or steam from a single fuel source. Often natural gas is used to produce both electricity and steam. The steam produced is normally required by an associated or nearby commercial facility, while the electricity generated is sold to a utility or used within the facility.

Cogeneration provides facilities with greater efficiency, greater reliability and increased process flexibility than conventional generation methods. Examples of industries using cogeneration facilities include food processing, pulp and paper and chemical plants.

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

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

(ii) Principal Markets and Distribution Methods

The principal markets of APUC's cogeneration facilities are California and Connecticut. The electricity produced from these facilities is conveyed from the relevant facility to the electricity markets either under the terms of long-term contracts or according to Independent System Operator rules. In addition to grid sales of electricity and power, electricity and thermal energy is also sold to onsite or adjacent third party thermal host facilities for use in production.

(1) California

The electric transmission system and wholesale markets in California are primarily regulated by the California Public Utilities Commission and FERC. The California Independent System Operator administers the wholesale electricity marketplace for the region.

(2) Connecticut

The electricity markets and transmission systems in Connecticut are governed by the Independent System Operator New England ("**ISO-NE**"). ISO-NE was established as a not-for-profit, private corporation on July 1, 1997 following its approval by FERC. The organization immediately assumed responsibility for managing the New England region's electric bulk power generation and transmission systems and administering the region's open access transmission tariff.

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

(iii) Material Facilities

(1) Sanger Thermal Facility

The Sanger thermal facility (the "**Sanger Thermal Facility**") is a 56MW natural gas-fired generating facility located in Sanger, California. The facility is a combined cycle generating station comprised of a 44 MW General Electric LM6000 PC Sprint gas turbine, commissioned in 2008, and a 12.5 MW Westinghouse steam turbine, originally commissioned in 1991. In 2012, APUC successfully completed a major upgrade at the Sanger Thermal Facility that involved an overhaul of the steam turbine, the replacement of the steam turbine generator, and the installation of a new 115kV transformer sized to manage the full output of the facility. The Sanger Thermal Facility is owned by Algonquin Power Sanger LLC, a subsidiary of APFA.

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

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

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

(2) Windsor Locks Thermal Facility

The Windsor Locks Thermal Facility has a total installed capacity of 71 MW. The facility is a combined cycle generating station comprised of a 40 MW General Electric natural gas fired turbine and a 16 MW General Electric steam turbine both

commissioned in 1990, and a 15 MW Solar Titan 130 combustion turbine installed in 2012. The Windsor Locks Thermal Facility is owned by Algonquin Power Windsor Locks LLC.

The Windsor Locks Thermal Facility supplies thermal steam energy and the majority of the output from the Solar Titan combustion turbine to Ahlstrom, a leading paper and non-woven materials manufacturer, pursuant to a ground lease and an Energy Services Agreement (the "**ESA**"). Pursuant to the ESA, Ahlstrom leases the facility site to Algonquin Power Windsor Locks LLC and utilizes thermal steam energy and a portion of electrical generation of the Windsor Locks Thermal Facility for use at its specialty fibers composites mill located adjacent to the Windsor Locks Thermal Facility. Payments under the ESA are fully indexed to the cost of natural gas consumed by the Windsor Locks Thermal Facility.

With the current configuration, 90% of the output of the baseload electrical generation is generated by the Solar Titan combustion gas turbine and is sold to Ahlstrom. The additional installed capacity at the site is committed to the ISO-NE market in the day ahead energy market, and the capacity and reserve markets as appropriate. Each MW generated by the Solar Titan combustion turbine qualifies for the production of RECs. Each REC is then sold into the ISO-NE market.

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

(iv) Renewable Energy Credits

RECs are tradable commodities representing the generation of 1 MWh of electricity, and are used by utilities to satisfy compliance with Renewable Portfolio Standards ("**RPS**") where necessary. These RPS mandates are set at a state level, and stipulate a certain amount of electricity to be generated from renewable sources by a specific year. These targets range from 10-40%, with some initial deadlines having already passed, and some stretching to 2025 and beyond. At the current time the Windsor Locks Thermal Facility produces and sells RECs through bilateral contracts.

Business Development

(i) Strategy

The Development Division works to identify, develop and construct new, renewable and efficient power generating facilities, as well as to identify, develop and construct other accretive projects that maximize the potential of APUC's existing facilities. Development is focused on projects within North America with a commitment to working proactively with all stakeholders, including local communities. It utilizes existing industry relationships to assist in the identification, evaluation, development and construction of projects, and retains expertise, as required, from the financial, legal, engineering, technical, and construction sectors. APUC's approach to project development is to maximize the utilization of internal resources while minimizing external costs. This allows development projects to evolve to the point where most major elements and uncertainties of a project are quantified and resolved prior to the commencement of project construction. Major elements and uncertainties of a project include the signing of a PPA, obtaining the required financing commitments to develop the project, completion of environmental permitting, and fixing the cost of the major capital components of the project. It is not until all major aspects of a project are secured that construction will proceed.

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

(ii) Principal Market Environment

APUC believes that future opportunities for power generation projects will continue to develop as new targets are set for renewable and other clean power generation projects.

Within Canada, the market is driven largely by provincial regulations, of which Ontario and Saskatchewan are expected to present the most immediate opportunities for Algonquin. The Ontario government, through the Independent Electricity System Operator ("**IESO**") is conducting a process to receive Requests For Proposals ("**RFP**"s) for up to 300 MW of wind power, up to 140 MW of solar power and up to 50 MW of hydro power with responses due in 2015. In 2014, Algonquin was one of a number of parties that were qualified to participate in future RFPs. Nova Scotia also continues to offer its community feed-in-tariff program, albeit on a smaller scale.

Within the United States, the most notable stimulus for the development of renewable power is the federal renewable electricity production tax credit ("**PTCs**" or "**Production Tax Credits**"), a per-kilowatt-hour tax credit for electricity generated by qualified energy resources, and the federal investment tax credit ("**ITCs**" or "**Investment Tax Credits**"), a tax credit for qualified renewable energy facilities based upon a percentage of eligible capital costs. Absent a further legislative extension, in order for a renewable power facility to be eligible for PTCs, construction of the facility must have been commenced by December 31,

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

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

(iii) Current Development Projects

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

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

1 PPA Signed.

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

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

4 The Val Eo Wind Project is being developed in two phases: Phase I of the project (24 MW) will be erected in 2015 and the101 MW Phase II of the project will be constructed following evaluation of the wind resource at the site, completion of satisfactory permitting and entering into appropriate energy sales arrangements.

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

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

(1) Morse Wind Project

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

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

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

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

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

(2) Bakersfield I Solar Project

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

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

(3) Odell Wind Project

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

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

(4) Val-Eo Wind Project

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

The Generation Group's equity interest in the project is subject to final negotiations with the Val-Eo community cooperative but, in any event, will not be less than 25%. It is believed that the first 24MW phase of the Val-Eo Wind Project will qualify as Canadian Renewable Conservation Expense and therefore the project will be entitled to a refundable tax credit equal to approximately $18.0 million.

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

(5) Bakersfield II Solar Project

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

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

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

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

(6) Amherst Island Wind Project

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

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

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

(7) Chaplin Wind Project

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

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

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

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

(8) Ontario RFP Qualification

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

(iv) Future Development Projects – Greenfield Projects

The company continues to pursue new development opportunities as well as build upon an existing portfolio of green-field sites. These projects represent a diversified range of opportunities within hydro, solar, wind and natural-gas modes of generation and are located throughout North America.

3.1.3 Specialized Skill and Knowledge

The Generation Group's employees, also have extensive experience and contacts in the independent power industry in Canada and the United States. The energy from hydrology aspect of the business of the Generation Group requires specialized knowledge of hydraulic turbines and their various components. This specialized knowledge is available to the Generation Group in-house.

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

3.1.4 Competitive Conditions

Deregulation has increased demand for privately generated power from a variety of sources including fossil fuels, waste, wind, water, and solar. With deregulation and opening of competition in the electricity marketplace, there should be an increase in the opportunity for the energy customer to choose the type of generation producing the electricity.

The US Department of Energy ("**USDOE**") has suggested that in a competitive marketplace, utilities and energy marketers will utilize green power pricing to strengthen their image with their customers and build customer loyalty. Further, the USDOE has found that most utility customers want their utilities to pursue environmentally benign options for generating electricity and some customers are willing to pay extra to receive power generated by renewable resources. The USDOE believes that as deregulation and open competition evolve, the green power approach will help offset the relatively higher costs of renewable power compared to less costly gas-fired generation. Additionally, programs and policies are evolving at all government levels, allowing for the trading of greenhouse gas credits created by renewable energy projects to be seen as part of the eventual solution.

Unlike electricity generated by fossil fuels such as natural gas and coal which are subject to potentially dramatic and unexpected price swings due to disruptions in supply or abnormal changes in demand, the supply of hydroelectric, wind and solar power is not subject to commodity fuel price volatility or risk. In addition, generation of the above forms of power generation do not involve significant ongoing capital and operating costs to ensure strict compliance with environmental regulations, which is a significant advantage over power generated by burning waste or utilizing landfill gases.

Taking into account capital costs, wind and solar power is generally more expensive than traditional forms of generated power, but costs have been decreasing with the increased demand for renewable energy, market competitiveness and improvements in generating technology. With production tax incentives, renewable portfolio standards, and improved equipment capacity factors, wind energy is approaching parity with market pricing for electricity in many jurisdictions.

APUC believes that future opportunities for power generation projects will continue to arise given that many jurisdictions, both in Canada and the United States, continue to increase targets for renewable and other clean power generation projects.
APUC is ideally positioned to take advantage of this demand for increased renewable energy, given that a significant portion of its assets are from renewable sources. It has experience and knowledge in the area. APUC will continue to actively pursue development projects which provide the opportunity to exhibit accretive growth. APUC anticipates its involvement in many future opportunities as initiatives designed to support independent power producers are being supported by virtually every Canadian province and a significant number of U.S. States.

3.1.5 Cycles & Seasonality

(i) Hydroelectric Generating Facilities

The Generation Group's hydroelectric operations are impacted by seasonal fluctuations and year to year variability of the available hydrology. These assets are primarily "run-of-river" and as such fluctuate with natural water flows. During the winter and summer periods, flows are generally lower while during the spring and fall periods flows are generally higher. The ability of these assets to generate income may be impacted by changes in water availability or other material hydrologic events within a watercourse. Year to year the level of hydrology varies impacting the amount of power that can be generated in a year.

(ii) Wind Power Generating Facilities

The Generation Group's wind generation facilities are impacted by seasonal fluctuations and year to year variability of the wind resource. During the spring and fall periods, winds are generally stronger than during the summer periods. The ability of these facilities to generate income may be impacted by naturally occurring changes in wind patterns and wind strength.

(iii) Energy Marketing of the Tinker Generating Facility

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

(iv) Solar Power Generating Facilities

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

3.1.6 Customers

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

3.2 Distribution Group

3.2.1 Regulatory Regimes - Utility Distribution Systems

Investor-owned utilities, whether water Distribution and waste water collection systems, electric distribution systems or gas distribution systems, are generally subject to economic regulation by the public utility commissions of the states in which they operate. The respective public utility commissions typically have jurisdiction over rates, service, accounting procedures, issuance of securities, acquisitions and other matters. The utilities generally operate under cost-of-service regulation as administered by these state authorities, using a test year in the establishment of rates for the utility and pursuant to this method the determination of the rate of return on approved rate base and deemed capital structure, together with all reasonable and prudent costs, establishes the revenue requirement upon which each utility's customer rates are determined. Rates charged by these utilities are determined such that rates are set so as to provide the utilities with sufficient revenues to generate after-tax equity returns of approximately 8% to 12%. This oversight and other rules set by the state utility commissions are intended to ensure adequate supplies of water, electricity and natural gas together with financial security, transparency in the rate setting process and reasonable prices.

(i) Water Distribution and Waste Water Collection Systems

Generally, water and wastewater providers in the United States operate as geographic monopolies within the areas in which they serve. A water or wastewater company is typically provided a service territory defined by a Certificate of Convenience and Necessity ("**CC&N**") which imposes an exclusive right and duty to serve in the service territory. A CC&N is typically granted by a State agency, which also serves as an economic and service quality regulator for these water or wastewater service providers. Such agencies are charged with ensuring that water and wastewater services are provided at reasonable rates and quality to the company's customers. The agency must balance the interests of the utility customers as well as companies and their shareholders. Rates are approved by the agency to provide the water or wastewater company the opportunity, but not the guarantee, to earn a reasonable return on its investment after recovering its prudently incurred operating expenses.

(ii) Electric Distribution Systems

The electricity industry is highly regulated in the United States. The industry is regulated under strict standards at multiple levels - federal, state and sometimes local. Under the FPA, FERC regulates interstate transmission, wholesale sales of electricity, corporate acquisitions and dispositions, securities and debt issuances, debt acquisitions, and reliability. State utility commissions perform a similar role, regulating sales of electricity to end-use customers, as well as financial stability and reliability.

Generally, electricity distribution companies in the United States operate as geographic monopolies within the areas in which they serve. An electricity distribution company is typically provided a CC&N which imposes an exclusive right and duty to serve in the service territory. The approval to serve is typically granted by a State agency, which also serves as an economic and service quality regulator for these electric service providers. Such agencies are charged with ensuring that electric services are provided at reasonable rates and quality to the company's customers. The agency must balance the interests of the rate payers as well as companies and their shareholders. Rates are approved by the agency to provide the electric service company

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

(iii) Natural Gas Distribution Systems

The natural gas industry is regulated at multiple levels - federal, state and sometimes local. Under the U.S. Natural Gas Act, FERC regulates interstate transmission and wholesale sales of gas. Interstate pipeline safety is regulated by the Department of Transportation. State utility commissions regulate retail distribution and sales of natural gas and intrastate pipelines. The federal pipeline safety requirements are often adopted by the state utility commissions and applied to intrastate pipelines and local distribution companies.

Generally, natural gas distribution companies in the United States operate as geographic monopolies within the areas in which they serve. A natural gas distribution company is provided a service territory which imposes an exclusive right and duty to serve in the service territory. The approval to serve is typically granted by a State agency, which also serves as an economic and service quality regulator for these natural gas service providers. Such agencies are charged with ensuring that natural gas services are provided at reasonable rates and quality to the company's customers. The agency must balance the interests of the rate payers as well as companies and their shareholders. Rates are approved by the agency to provide the natural gas utility the opportunity, but not the guarantee, to earn a reasonable return on its investment after recovering its prudently incurred operating expenses.

3.2.2 Description of Operations

Water Distribution and Waste Water Collection Systems

(i) Method of Providing Services and Distribution Methods

A water utility services company provides regulated utility water supply and/or wastewater collection and treatment services to its customers.

A water utility sources, treats and stores potable water and subsequently distributes it to its customers through a network of buried pipes (distribution mains). A wastewater utility collects wastewater from its customers and transports it through a network of collection pipes, lift stations and manholes to a centralized facility where it is treated, rendering it suitable for discharge to the environment or for reuse, usually as irrigation.

The raw water for human consumption is sourced from the ground and extracted through wells or from surface waters such as lakes or rivers. The water is treated to potable water standards that are specified in Federal and State regulations and which are typically administered and enforced by a State or local agency. Following treatment, the water is either pumped directly into the distribution system or pumped into storage reservoirs from which it is subsequently pumped into the distribution system. This system of wells, pumps, storage vessels and distribution infrastructure is owned and maintained by the private utility.

The fees or rates charged for water are comprised of a fixed charge component plus a variable fee based on the volume of water used. Additional fees are typically chargeable for other services such as establishing a connection, late fee, reconnects, etc.

In respect of sewer or wastewater services, the sewage or wastewater produced by the customer flows through a buried service lateral line, which the line is owned and maintained by the customer, from the house or commercial space to the street. This line feeds into collection pipes or lines (collection mains) located under or adjacent to the street which pipes are owned and maintained by the private utility. These pipes generally slope at a grade of approximately 0.25% as gravity is generally relied on to facilitate flows. On long line runs where maintaining slopes would result in excessive depths below grade or to traverse variable terrain, the line may terminate at a lift station where wastewater is collected and then pumped up to feed into another line located closer to the surface level where the wastewater can continue to flow by gravity. This is typically referred to as a "force main".

The wastewater is ultimately delivered to a treatment plant. Primary treatment at the plant consists of the screening out of larger solids, floating material and other foreign objects and, at some facilities, grit removal. These removed materials are hauled to a landfill. Secondary treatment at the plant consists of biological digestion of the organic and other impurities which is performed by beneficial bacteria in an oxygen enriched environment. Excess and spent bacteria are collected from the bottom of the tanks digested and or dewatered and the resulting solids sent to landfill or to land application as a soil amendment. The treated water, referred to as "effluent", is then used for irrigation or groundwater recharging or is discharged by permit into adjacent surface waters. The standards to which this wastewater is treated are specified in each treatment facility's operating permit and the wastewater is routinely tested to ensure its continuing compliance therewith. The effluent quality standards are based on Federal and State regulations which are administered and continuing compliance therewith enforced by the State agency to which Federal enforcement powers are delegated.

(ii) Principal Markets and Regulatory Environments

The Company's water and wastewater facilities are located in the United States of America in the states of Arizona, Texas, Missouri, Arkansas, and upon closing of the Park Water acquisition, in the states of California and Montana. The water and wastewater utilities are generally subject to regulation by the public utility commissions of the States in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters. These utilities generally operate under cost-of-service regulation as administered by these state authorities. The utilities generally use a historic test year in the establishment of rates for the utility and pursuant to this method the determination of the rate of return on approved rate base, recovery of depreciation on plant, together with all reasonable and prudent operating costs, establishes the revenue requirement upon which each utility's customer rates are determined.

Rate cases ensure that a particular facility appropriately recovers its operating costs and has the opportunity to earn a rate of return on its capital investment as allowed by the regulatory authority under which the facility operates. The Company monitors the rates of return on each of its water and wastewater utility investments to determine the appropriate time to file rate cases in order to ensure it earns the regulatory approved rate of return on its investments. A summary of the rates and tariffs for the wastewater treatment and water distribution business unit is attached in Schedule C.

(1) Arizona

The Arizona Corporation Commission ("**ACC**") is the primary regulatory agency with jurisdiction over water and wastewater treatment utilities in Arizona. The Arizona Department of Environmental Quality ("**ADEQ**") and the Arizona Department of Water Resources in conjunction with various County agencies (county health units) have primary jurisdiction respecting environmental regulation and compliance.

(2) Texas

The Public Utility Commission of Texas ("**PUC Texas**") is the primary regulatory agency with jurisdiction over water and wastewater treatment utilities in Texas. This regulatory responsibility was transferred from the Texas Commission on Environmental Quality (the "**TCEQ**") to the PUC Texas on September 1, 2014. The TCEQ has regulatory jurisdiction respecting environmental compliance, including implementing and enforcing the standards mandated by the federal Clean Water Act and the Safe Drinking Water Act, for all water and wastewater treatment service providers, including those owned and operated by municipalities.

(3) Arkansas

The Arkansas Public Service Commission ("**PSC**") is the primary regulatory agency with jurisdiction over the private and investor owned water utilities in Arkansas for rates and charges. The Arkansas Department of Health has regulatory jurisdiction respecting environmental compliance, including implementing and enforcing the standards mandated by the federal Clean Water Act and the Safe Drinking Water Act, for all water treatment service providers, including those owned and operated by municipalities. The Arkansas Department of Environmental Quality is the primary regulator for all discharge permits including wastewater treatment utilities in Arkansas.

(4) California

The California Public Utilities Commission ("**CPUC**") is the primary regulatory agency with jurisdiction over the private and investor owned water utilities in California for rates and charges. The Division of Drinking Water of the California State Water Resources Control Board ("**SWRCB**") has regulatory jurisdiction respecting environmental compliance, including implementing and enforcing the standards mandated by the California Safe Drinking Water Act and Title 17 and 22 of the California Code of Regulations (California has primacy) for all water service providers, including those owned and operated by municipalities., that jurisdiction of drinking water for CPUC-regulated water providers is shared between the CPUC and SWRCB pursuant to a Memorandum of Understanding. The California State Water Resources Control Board is the primary regulator for all discharge permits from drinking water systems in California.

(5) Montana

The Montana Public Service Commission ("**MNPSC**") is the primary regulatory agency with jurisdiction over the private and investor owned water utilities in Montana for rates and charges. The Montana Department of Environmental Quality has regulatory jurisdiction respecting environmental compliance, including implementing and enforcing the standards mandated by the federal Safe Drinking Water Act, for all water service providers, including those owned and operated by municipalities. The Montana Department of Environmental Quality is the primary regulator for all discharge permits in Montana.

(iii) Material Facilities

(1) Gold Canyon Water System

The Gold Canyon water system (the "**Gold Canyon Water System**") is a wastewater treatment facility established in 1984 to serve a number of residential developments and an unincorporated area of Pinal County referred to as Gold Canyon, approximately 25 miles east of downtown Phoenix, Arizona.

The Gold Canyon Water System currently serves over 7,500 residential and commercial connections. The treatment plant utilizes a biological nutrient removal process combined with a sequencing batch reactor with a treatment capacity of 1.9 million gallons per day ("**gpd**").

The Gold Canyon Water System is a consumptive re-use facility and sells its reclaimed A+ effluent for use as irrigation water on two neighboring golf courses. Excess reclaimed water is recharged (put back into the ground to replenish underground water) via three recharge ponds. The treatment facility operates under ADEQ – Aquifer Protection Permits and Reuse Permits.

(2) LPSCo Water & Wastewater Systems

The LPSCo water distribution and wastewater treatment facility ("**LPSCo System**") located in the city of Goodyear, 15 miles west of Phoenix, Arizona whose service area includes the City of Litchfield Park and sections of the cities of Goodyear and Avondale as well as portions of unincorporated Maricopa County.

Connection Base

The LPSCo System presently serves approximately 19,000 water and 21,100 wastewater connections. The wastewater system has permitted capacity of 54.1 million gpd. The water infrastructure system includes a total of twelve active wells, a 6.3 million gallon reservoir and a 4.0 million gallon reservoir which provides water to the current connection base through a single pressure zone. . The LPSCo System now operates at approximately 80% of design capacity. The LPSCo System supplies Class "A+" effluent to a number of local golf courses in the area. The LPSCO System's largest 10 connections represent approximately 11.5% of its total annual sales of approximately U.S. $23.1 million. Its largest customers are the City of Goodyear and an elementary school.

Rate Case

On February 28, 2013, LPSCo Water System filed a general rate case with the Arizona Corporation Commission seeking, among other things, an increase in EBITDA by U.S. $3.0 million over the 2012 results if approved as filed. The application sought recognition of increased capital investment and increased operating expenses over current rates. In addition to a revenue increase, the application sought for an accelerated infrastructure recovery surcharge, a purchased power pass-through mechanism to recover power price increases between test years, a property tax accounting deferral to defer increases in property taxes between test years and a policy statement on rate design to begin the gradual shift of moving more revenue recovery to fixed charges versus commodity charges. In April 2014 the commission approved a $1.8 million increase in rates effective on May 1, 2014.

Financing

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

(3) Rio Rico Water & Wastewater Systems

The Rio Rico water & wastewater systems (the "**Rio Rico System**") is a water distribution and wastewater facility located in Santa Cruz County, Arizona approximately 60 miles south of Tucson, Arizona.

The Rio Rico System serves approximately 6,800 water and 2,200 wastewater connections in the community of Rio Rico, Arizona. The Rio Rico System has separate water and wastewater Certificates of Convenience and Necessity and is regulated by the ACC.

(4) Pine Bluff Water System

The Pine Bluff Water System is a regulated water utility located in the City of Pine Bluff, Arkansas in Jefferson County. The system is regulated by the Arkansas Public Service Commission and has a franchise agreement with the City of Pine Bluff, Arkansas.

Connection Base

The Pine Bluff Water System serves a population of over 50,000 people comprising approximately 17,800 connections. During the year ended December 31, 2014, the Pine Bluff Water System's largest 10 connections represent approximately 38.1% of its total annual sales of approximately U.S. $8.8 million. Its largest customers are a food processing company, public works facilities and a university.

Rate Case

On July 2, 2014, Pine Bluff Water System filed an application with the APSC seeking an increase in revenue of U.S. $2.5 million based on a test year ending January 31, 2014, with pro forma changes to certain operating expenses and rate base capital additions. The previous test year ended September 30, 2009. An Order and new rates are expected in the second quarter of 2015.

(5) Acquisition of the Park Water System

In 2014 the company announced that it has entered into an agreement to purchase the regulated water distribution utility Park Water Company ("**Park Water System**"). The Park Water System owns and operates three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in Southern California and Western Montana. The three utilities collectively serve approximately 74,000 customer connections and have more than 1,000 miles of distribution mains.

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

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

Electric Distribution Systems

(i) Method of Providing Services and Distribution Methods

Electric distribution is the final stage in the delivery system of providing electricity to end users. An electric distribution system's network carries electricity from the transmission system and delivers it to consumers or other end users. Typically, the network includes medium-voltage (less than 50 kV) power lines, electrical substations, various line apparatus (reclosers, fuses, lightning arrestors), and distribution transformers (pole mounted or pad-mounted), low-voltage (less than 1 kV) secondary distribution wiring and then electric meters used for billing.

An electric distribution utility sources and distributes electricity to its customers through a network of buried or overhead lines. The electricity is sourced from power generation facilities which can use various fuels such as water (hydro), natural gas, coal, bio-mass, wind, nuclear and solar. The electricity is transported from the source(s) of generation at high voltages through transmission lines and is then reduced through transformers to lower voltages at substations. The electricity from the substations is then delivered through distribution lines to the customers where the voltage is again lowered through a transformer for use by the customer.

The rates charged for electric distribution service are comprised of a fixed charge that recovers customer related costs, such as meter readings, and a variable rate component that recovers the cost of generation, transmission and distribution. Other revenues are comprised of fees for other services such as establishing a connection, late fee, reconnections, and energy efficiency programs, for example.

The electrical distribution utilities located in California and New Hampshire are subject to state regulation and rates charged by these utilities must be reviewed and approved by their respective State regulatory authorities.

(ii) Principal Markets and Regulatory Environments

The Company operates electrical distribution systems in the states of California and New Hampshire under a cost-of-service methodology. The utilities use an historical test year, pro-formed for known and measurable changes, in the establishment of their rates. Pursuant to this method, the revenue requirement upon which rates are based is determined by applying an approved return on rate base, and adding depreciation, operating expenses and administrative and general expenses.

Rate cases ensure that a particular utility recovers its operating costs and has the opportunity to earn a reasonable rate of return on its capital investment as allowed by the regulatory authority under which the utility operates. The Company monitors the rates of return on its utility investments to determine the appropriate times to file rate cases in order to ensure it earns a

reasonable rate of return on its investments. In the case of the CalPeco Electric System a rate case filing is mandatory every 3 years. A summary of the rates and tariffs for the Company's Distribution Group's electric distribution utilities is attached in Schedule D.

(1) California

The CPUC regulates investor owned utilities in California and approves the rate of return and the rate base which affects the profitability of the utility.

Energy Cost Adjustment Clause ("**ECAC**") is an annual filing that sets rates to recover the next year's fuel and purchased power costs in addition to setting rates to recover or refund any under/over recovery of previous year's fuel and purchased power costs.

Post Test Year Adjustment Mechanism ("**PTAM**") allows the CalPeco Electric System to update its rates annually by a cost inflation index. In addition, rates are updated to recover the return on investment and associated depreciation of major capital projects that are placed in service and meet a certain cost threshold.

The Base Revenue Requirement Balancing Account ("**BRRBA**") removes the seasonal variations of the revenues and flattens the net revenue (minus fuel, purchased power, and ECAC) to a monthly rate of $3.0 million or $36.0 million annually. This eliminates the risk of revenue variations associated with seasonal weather changes.

(2) New Hampshire

The NHPUC is vested with general jurisdiction over electric, telecommunications, natural gas, water and sewer utilities as defined in applicable legislation for issues such as rates, quality of service, finance, accounting, and safety. New Hampshire introduced "retail choice" for customers in 1998. Utility companies are allowed to file distribution rate cases from time to time as the companies determine a need to request adjustments to base rates. There are a number of adjustment factors also in rates, for reliability enhancement programs, vegetation management, energy efficiency and low income programs, all of which are reconciled on an annual basis. Electricity distribution companies are also required to provide electricity commodity service for its customers who do not elect to take service from a competitive supplier. Costs for commodity service are recovered on a direct pass through basis.

(iii) Material Facilities

(1) CalPeco Electric System

The CalPeco Electric System provides electric distribution service to the Lake Tahoe basin and surrounding areas. The service territory, centered on a highly popular tourist destination, has a customer base spread throughout Alpine, El Dorado, Mono, Nevada, Placer, Plumas and Sierra Counties in northeastern California. The distribution system is comprised of approximately 94 miles of high voltage distribution lines, 13 substations, and 39 distribution circuits (14.4 kV) serving approximately 48,300 connections.

Connection Base

CalPeco Electric System's connection base of approximately 48,300 connections is primarily residential with large commercial accounts limited to less than 20% of gross revenues. The commercial connections consist primarily of ski resorts, hotels, hospitals, schools and grocery stores. The CalPeco Electric System's largest 10 connections represent approximately 14.6% of its total annual sales of approximately U.S. $73.2 million. Its largest customers are major ski resorts and large region school district.

Rate Case

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

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

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

Kings Beach Generation

The CalPeco Electric System has a local-area emergency backup generation facility at Kings Beach in Placer County, California. The facility consists of six new Caterpillar 3516 Engine diesel generation units with a total nameplate capacity of 12 MW. The units were installed in November 2008 at a cost of U.S. $16.5 million and have an estimated useful life of 30 years. The repowered facility meets all California environmental standards. Any non-preventative maintenance expenditures that may occur during the first five years of operation will be fully covered by the Manufacturer's warranty.

In the event of a system outage, the Kings Beach Facility is able to provide limited back-up generation support to the CalPeco Electric System's service territory until baseload power is restored. The facility includes quick-start technology which facilitates this support function. The new units are designed to be online and operating within 1 minute of being activated. The Kings Beach Facility has historically run an average of 200 hours per year.

Energy Cost Adjustment Clause

ECAC is an annual filing that sets "base rates" to recover the next year's fuel and purchased power costs in addition to setting "amortization rates" to recover or refund any under/over recovery of previous year's fuel and purchased power costs. Rates are effective January 1st of every year.

Post Test Year Adjustment Mechanism

In years where the CalPeco Electric System does not file a general rate case, its rates are updated on January 1st to reflect inflationary increases to its administrative, operations, and maintenance costs. The inflationary adjustment is set by the use of an index, less a presumed efficiency offset.

The CalPeco Electric System may also file for an annual increase in rates to recover its investment costs in material capital projects. This increase is subject to a materiality threshold.

Base Revenue Requirement Balancing Account

BRRBA is used to record the difference between the CalPeco Electric System's CPUC authorized annual base rate revenue requirements and the annual recorded revenue from base rates. The disposition of the balance in the BRRBA will be addressed by an annual filing.

PPA

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

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

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

Financing

The CalPeco Electric System entered into a long term debt private placement in an amount of U.S. $70.0 million on December 29, 2010. The private placement is a senior unsecured private placement with U.S. institutional investors. The notes are fixed rate, interest only, and split into two tranches, U.S. $45.0 million of ten year 5.19% notes and U.S. $25.0 million of 5.59% fifteen year notes.

(2) Granite State Electric System

The Granite State Electric System provides distribution service to approximately 44,600 connections in 21 communities located in two franchise service areas in southern and northwestern New Hampshire, centered around operating centers in Salem in the south and Lebanon in the northwest. Across approximately 810 square miles of service area, the Granite State Electric System's assets consist of 908 miles of overhead distribution lines, 231 miles of underground distribution lines, 15 distribution substations, 37 distribution circuits and 9 sub-transmission circuits.

Connection Base

The Granite State Electric System's customer base consists of a mixture of residential, commercial and industrial customers. The system's residential customer base represents approximately 38,000 connections, while the commercial and industrial customer base represents approximately 6,700 connections. The commercial and industrial connections are a mix of commercial, retail, medical, education and manufacturing with its largest 10 connections representing approximately 11.9%

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

Rate Case

In the first quarter of 2013, the Granite State Electric System filed a rate case with the NHPUC which sought an increase in rates of U.S. $13.0 million, and an additional U.S. $1.2 million increase in 2014 subject to the completion of certain capital projects. On March 17, 2014, the commission approved a settlement of U.S. $9.8 million and U.S. $1.1 million step increase for 2014. The rates came into effect April 1, 2014.

Default Service Adjustment Provision

Granite State Electric System is required to provide electric commodity supply (Default Service) for all customers who do not choose to take supply from a competitive supplier in the New England power market. The competitive market is overseen by the ISO-NE. As an electric distribution utility, Granite State Electric System is required to participate in the ISO-NE market and abide by its rules under FERC. The Granite State Electric System is allowed to fully recover its costs for the provision and administration of Default Service under the Default Service Adjustment Provision, as approved by the NHPUC. The Granite State Electric System must file with the NHPUC twice a year to adjust for market prices of power purchased.

Financing

Outstanding third party indebtedness at the Granite State Electric System consists of unsecured notes issued in three tranches for an aggregate amount of U.S. $15.0 million: U.S. $5.0 million bearing an interest rate of 7.37%, maturing November 1, 2023; U.S. $5.0 million bearing an interest rate of 7.94%, maturing July 1, 2025; and U.S. $5.0 million bearing an interest rate of 7.30%, maturing June 15, 2028. The notes are interest only and payable semi-annually.

Natural Gas Distribution Systems

(i) Method of Providing Services and Distribution Methods

Natural gas is a fossil fuel composed almost entirely of methane (a hydrocarbon gas) usually found in deep underground reservoirs formed by porous rock. In making its journey from the wellhead to the customer, natural gas may travel thousands of miles through interstate pipelines owned and operated by pipeline companies.

Because gas flowing from higher to lower pressure is the fundamental principle of the natural gas delivery system, compressor stations may be located every 50-60 miles along the pipelines to boost pressure that is lost through friction. Also along the route, the natural gas may be stored underground in depleted oil and gas wells or other natural geological formations for use during seasonal periods of high demand.

Interstate pipelines interconnect with other pipelines and other utility systems, and offer system operators flexibility in moving the gas from point to point. The interstate pipeline companies are regulated by the FERC. The gas is transported from various sources at high pressures through transmission lines and is then reduced through gate stations to distribution pressures.

The gas from the gate stations is then delivered through distribution lines to the customer where the gas pressure is again lowered through district regulator stations and/or meter regulators for use by the customer. Typically, the distribution network operates pipelines, gate stations, district regulator stations, peak shaving plants and natural gas meters.

The gas distribution utilities owned by the Company are subject to state regulation and rates charged by these facilities may be reviewed and altered by the State regulatory authorities from time to time.

(ii) Principal Markets & Regulatory Environments

The Company owns and operates natural gas distribution systems, under cost-of-service regulation in the states of Illinois, Iowa, Missouri, Georgia, Massachusetts and New Hampshire. The natural gas utilities use a test year to determine distribution rates for the utility. Pursuant to this method, the revenue requirement upon which rates are based is determined by applying an approved return on rate base, and adding depreciation, operating expenses, and administrative and general expenses.

Rate cases ensure that a particular facility appropriately recovers its operating costs and has the opportunity to earn a reasonable rate of return on its capital investment as allowed by the regulatory authority under which the facility operates. The Company monitors the rates of return on its utility investments to determine the appropriate times to file rate cases in order to ensure it earns a reasonable rate of return on its investments. A summary of the rates and tariffs for the Company's Distribution Group' natural gas distribution utilities is attached in Schedule E.

(1) New Hampshire

In New Hampshire, gas utilities are regulated by the NHPUC. The NHPUC is vested with general jurisdiction over electric, telecommunications, natural gas, water and sewer utilities as defined in applicable legislation for issues such as rates, quality of service, finance, accounting, and safety.

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

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

(2) Illinois

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

The rates and fees for providing gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed Purchased Gas Adjustment.

(3) Iowa

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

The rates and fees for providing gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed Purchased Gas Adjustment.

(4) Missouri

The Company's Missouri operations are regulated by the MPSC.

The rates and fees for providing gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed Purchased Gas Adjustment.

(5) Georgia

The Company's Georgia operations are regulated by the Georgia Public Service Commission.

The rates and fees for providing gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed Purchased Gas Adjustment.

(6) Massachusetts

The Company's Massachusetts operations are regulated by the Commonwealth of Massachusetts. The Massachusetts Department of Public Utilities ("**MDPU**") has regulatory jurisdiction over all public utilities and common carriers operating in the commonwealth, which jurisdiction includes the establishment of approved tariffed rates for the purpose of billing customers.

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

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

(iii) Material Facilities

(1) EnergyNorth Gas System

The EnergyNorth gas system (the "**EnergyNorth Gas System**") is a regulated natural gas utility providing natural gas distribution services to approximately 92,100 connections in 30 communities covering five counties in New Hampshire. Its franchise service area includes the communities of Nashua, Manchester and Concord, New Hampshire. The EnergyNorth Gas System is the largest natural gas distribution utility in the State, with a distribution system consisting of 2,140 miles of distribution pipelines, 2.8 miles of transmission pressure gas pipelines and eight city gate stations, or distribution supply points.

Customer Base

The EnergyNorth Gas System's customer base consists of a mixture of residential, commercial, industrial and transportation customers. The system's residential customer base represents approximately 82,500 connections, while the commercial and industrial customer base represents approximately 9,600 connections. The commercial and industrial customer base is a diversified mix of retail, medical, educational and industrial uses. No one connection represents more than 3% of its connection base. The EnergyNorth Gas System's largest 10 connections represent approximately 2.2% of its total annual sales of approximately U.S. $152.8 million. Its largest customers are a technology company and multiple public works facilities.

Rate Case

On August 1, 2014, the EnergyNorth Natural Gas System in New Hampshire filed an application for a total increase in revenue of U.S. $16.1 million, or approximately 9.6%. This proposed increase consists of U.S. $13.4 million of permanent base distribution rates and a step increase of U.S. $2.65 million for investments made during a pro forma period. The application includes a revenue decoupling proposal and seeks recovery of capital costs related to the conversion of the system to the Company's ownership. Expected implementation of the new permanent rates is in the third quarter of 2015. A temporary rate increase was approved on November 21, 2014 allowing a U.S. $7.4 million interim rate increases effective December 1, 2014, retroactive to November 2014 upon approval of permanent rates.

Energy Cost Adjustment Clause

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

(2) Midstates Gas System

The Midstates Gas System owns regulated natural gas utilities providing natural gas distribution services to approximately 85,900 connections in 190 communities in the states of Illinois, Iowa and Missouri. The franchise service area includes the communities of Virden, Vandalia, Harrisburg and Metropolis in Illinois, Keokuk in Iowa, and Butler, Kirksville, Canton, Hannibal, Jackson, Sikeston, Malden and Caruthersville in Missouri. The Midstates Gas System has a distribution system consisting of 2,795 miles of distribution pipelines, 243 miles of transmission pressure gas pipelines and 102 city gate stations, or town border supply points.

Customer Base

The Midstates Gas System serves approximately 23,600 connections in Illinois, 4,500 connections in Iowa and 57,800 connections in Missouri with a mix of residential, commercial, industrial and transportation customers. Of the 85,900 connections, approximately 76,600 (89%) are residential connections, while 9,300 (11%) are commercial and industrial connections. The commercial and industrial connection base is a diversified mix of retail, medical, education and industrial uses. The Midstates Gas System's largest 10 connections represent approximately 7.2% of its total annual sales of approximately U.S. $81.8 million. Its largest customers are a biotechnology company and a manufacturing company.

Energy Cost Adjustment Clause

Illinois allows full recovery of all gas costs (including commodity price, transportation, reservation and demand costs, hedging costs, and storage costs). The rate is adjusted monthly with an annual reconciliation based on the calendar year. An annual reconciliation is filed based on the 12 months ended December.

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

Missouri allows full recovery of all gas costs (including commodity price, transportation, reservation and demand costs, hedging costs, and storage costs). The rate is adjusted annually (in fourth quarter) with allowance to file quarterly. An annual reconciliation is filed based on the 12 months ended August of each year.

(3) Peach State Gas System

The Peach State Gas System is a regulated natural gas system providing natural gas distribution services to approximately 58,100 connections in 13 communities covering six counties in Georgia. Its franchise service area includes the communities of Columbus, Gainesville, Waverly Hall, Oakwood, and Hamilton, GA. The regulated Peach State Gas System has a distribution system consisting of approximately 1,200 miles of distribution pipelines, approximately 70 miles of transmission pressure gas pipelines and four city gate stations, or distribution supply points.

Customer Base

The Peach State Gas System's customer base consists of a mixture of residential, commercial, industrial and transportation customers. The system's residential customer base represents approximately 53,800 connections, while the commercial and industrial customer base represents approximately 4,300 connections. The commercial and industrial customer base is a diversified mix of retail, medical, educational and industrial uses. No one connection represents more than 3% of its connection base. The utility also maintains and operates the distribution system for a large US Army military base, consisting of approximately 116 miles of distribution pipelines, through a special privatization contract. The Peach State Gas System's largest 10 connections represent approximately 5.7% of its total annual sales of approximately U.S. $70.4 million. Its largest customers are poultry and textile producers.

Rate Case

The Peach State Gas System's rates are reviewed and updated annually through a tariff provision called the Georgia Rate Adjustment Mechanism ("**GRAM**"). This mechanism allows for the annual review of cost recoveries and the setting of rate base returns with a target of 10.7% return on equity and a range of 10.5% to 10.9%. The mechanism includes a provision to "true up" revenues in the subsequent year to capture or refund under or over collections. The annual GRAM filing is due October 1st of each year and the rates approved through the filing go into effect February 1st of the following year. The mechanism includes a forward looking view of cost of service based on approved inflation factors and also includes certain forecasted capital expenditures.

On October 1, 2013, the Peach State Gas System filed an application for an increase in revenue of U.S. $4.9 million in its annual GRAM filing with the GPSC. In January 2014, the Company and the Staff of the GPSC agreed to a settlement which will provide an annual revenue increase of U.S. $3.2 million, and the recovery of U.S. $1.7 million of carrying charges on deferred rate base in a future GRAM filing. Commission approval was received in May 2014, with new rates effective as of June 1, 2014.

On October 1, 2014, the Peach State Gas System filed an application for an increase in revenue of U.S. $3.9 million in its annual GRAM filing with the GPSC. New rates to be effective February 1, 2015 for the period February 1, 2015, through January 31, 2016 were to reflect changes in revenue levels and cost of service. The GRAM uses a 12 month base period ending June 30, 2014 (Historic Test Year) with adjustments for the 12 months ending August 31, 2015 (Forward Looking Test Year). Commission approval was received on December 4, 2014.

The Peach State Gas System also files an annual Pipe Replacement Program revision to adjust the rates collected for capital costs incurred to replace cast iron and bare steel pipe in its system. The filing is made each February 15th and the rate adjustment, calculated using a 10.7% ROE, takes effect on October 1st of the same year. The program is due to be completed in two years at which time the rate base remaining under this program will be rolled into the annual GRAM filing.

Energy Cost Adjustment Clause

Georgia allows full recovery of all gas costs (including commodity price, transportation, reservation and demand costs, hedging costs, storage costs). The cost of gas delivered to customers is recovered when billed to "sales" gas customers through the operation of Purchased Gas Adjustment ("**PGA**") clauses included in utility tariffs. The PGA requires a change in rates at least every three months. Each year the utility files a gas supply plan on July 1st with an effective date of October 1st.

(4) New England Gas System

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

Customer Base

The New England Gas System's customer base consists of a mixture of residential, commercial, and industrial customers. The system's residential customer base represents approximately 52,200 connections, while the commercial and industrial customer base represents approximately 3,700connections. New England Gas System's distribution network consists of 609 miles of distribution main and 35,660 service lines. The New England Gas Systems receives gas at five delivery points or gate stations along the Algonquin Gas Transmission Company (Spectra Energy) transmission system. The New England Gas System's largest 10 connections represent approximately 4.1% of its total annual sales of approximately U.S. $73.2 million. Its largest customers are waste management and textile companies.

Rate Case

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

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

Energy Cost of Gas Adjustment Clause

The cost of gas is fully recoverable from customers through the Gas Adjustment Factor ("**GAF**") when billed to "firm" gas customers included in approved tariffs by the MDPU. The GAF is adjusted (May and November) and more frequently if the monthly gas cost forecast differs from the originally forecasted by >5%.

Financing

The New England Gas System currently has outstanding indebtedness in the form of first mortgage bonds consisting of three tranches for an aggregate amount of U.S. $19.5 million: U.S. $6.5, bearing an interest rate of 9.44%, maturing February 15, 2020; U.S. $7.0, bearing an interest rate of 7.99%, maturing September 15, 2026; U.S. $6.0, bearing an interest rate of 7.24%, maturing December 15, 2027. The notes have interest only payments, payable semi-annually in arrears.

3.2.3 Specialized Skill and Knowledge

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

In addition, the Distribution Group will add, when required, additional utility trained personnel at its corporate offices to support the expanded portfolio of utility assets.

3.2.4 Competitive Conditions

The Distribution Group's businesses have geographic monopolies in their service territories and are therefore insulated from competition. The Distribution Group has developed significant in-house regulatory expertise in order to effectively interact with the state regulators in the various jurisdictions in which it operates. The Distribution Group believes that the relationship with regulators is unique to each state and therefore is best delivered by local managers who work in the service territory. The local regulatory teams meet with regulatory agencies on regular basis to review regulatory policies, service delivery strategies, operating results and rate making initiatives

3.2.5 Cycles & Seasonality

(i) Water & Wastewater Systems

Demand for water is affected by weather conditions and temperature. Demand for water during warmer months is generally greater than cooler months due to requirements for irrigation, swimming pools, cooling systems and other outside water use. If there is above normal rainfall or rainfall is more frequent than normal the demand for water may decrease adversely affecting revenues.

Water distribution facilities depend on an adequate supply of water to meet present and future demands of customers. Drought conditions could interfere with sources of water supply used by the utilities and affect their ability to supply water in sufficient quantities to existing and future customers. An interruption in the water supply could have an adverse effect on the results of operations of the utilities. Government restrictions on water usage during drought conditions could also result in decreased demand for water, even if supplies are adequate, which could adversely affect revenues and earnings.

(ii) Electricity Systems

The CalPeco Electric System's demand for energy sales are primarily affected by weather conditions. Above normal snowfall in the Lake Tahoe area brings more tourists with an increased demand for electricity by small commercial customers. Prior to January 1, 2013, CalPeco Electric System was exposed to volume sales risk related to seasonal weather variations. Effective on January 1, 2013, pursuant to the CPUC General Rate Case decision, a BRRBA rate mechanism has been implemented. The BRRBA removes the seasonal variations of revenues and flattens the net revenue (gross revenues less fuel, purchased power, and the ECAC deferral) to a monthly amount of approximately $3.0 million or $36.0 million annually. This mechanism eliminates the risk of revenue variations associated with seasonal weather changes.

The Granite State Electric System experiences peak loads in both the winter and summer seasons, due to heating and cooling loads associated with New England weather. The competitive market for power supply is managed by the ISO-NE. The default service price for power may fluctuate as a result of the weather, but those costs are passed through directly to customers.

The Granite State Electric System offers a comprehensive menu of energy efficiency programs in New Hampshire that, in turn, may reduce the demand for energy. These programs are funded via a charge in distribution rates known as the systems benefit charge, which applies to all utilities. This mechanism provides for an annual reconciliation of costs. The company has an opportunity to earn a performance incentive if it is successful in achieving its annual energy efficiency targets.

(iii) Natural Gas Systems

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

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

3.2.6 Customers

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

3.3 Transmission Group

3.3.1 Regulatory Regimes - Pipeline Transmission Systems

Interstate natural gas pipeline transmission assets are regulated primarily by the FERC under the Natural Gas Act. Under this framework, this agency authorizes and certificates all construction, and or abandonment of interstate gas pipeline facilities, requires certificate holders, once operational, to establish and maintain an Open Access transmission tariff and publicly post capacity available for transportation, and the agency periodically reviews, under just and reasonable standards, the tariff rates to be charged by the certificate holder. In addition, the FERC prescribes operating and safety standards to be followed along with other federal agencies such as Department of Transportation and the Occupational Safety and Health Administration.

3.3.2 Description of Operations

Natural Gas Pipeline Transmission

(i) Method of Providing Services and Distribution Methods

Pipelines offer a variety of services under their FERC tariffs to include firm and interruptible transportation, along with other services to provide commercial markets additional flexibility. Some examples of these types of services would be park and loan, pooling and balancing services. In addition, firm service tariff features would also provide additional features to support secondary market activity to include, but not limited to capacity assignment, capacity releases, segmentation and renewal options. Under the FERC environment, a shipper must have the good right or title to the gas for transportation. Under the FERC regulations, a considerable amount of daily and current information about each pipeline system capacity and related shipper and capacity information is available on their public Electronic Bulletin Boards or public websites.

(ii) Investments

(1) Northeast Expansion Project

On November 24, 2014, APUC announced its agreement to participate in a natural gas pipeline transmission project in partnership with Kinder Morgan, Inc. Specifically, Kinder Morgan Operating L.P. “A,” a wholly owned subsidiary of Kinder Morgan, Inc., and Liberty Utilities (Pipeline & Transmission) Corp., a wholly owned subsidiary of APUC, have agreed to form Northeast Expansion LLC to undertake the development, construction and ownership of a 30-inch or 36-inch natural gas

transmission pipeline to be located between Wright, New York and Dracut, Massachusetts (the "**Project**"), which will be operated by Tennessee Gas Pipeline Company, L.L.C. ("**Tennessee**") . The Project is scalable up to 2.2 billion cubic feet per day (Bcf/d), and the pipeline capacity will be contracted with local distribution utilities, and other customers, to help ease constraints on natural gas supply in the northeast U.S. and help ensure much needed reliability to the power-generation grid. It is anticipated that Tennessee will receive a FERC certificate in the fourth quarter of 2016, with commercial operations occurring by late 2018. Under this framework, Tennessee, as Operator, would be regulated by the FERC.

3.4 Business Associations with APMI and Senior Executives

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

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

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

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

Due to and from related parties

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

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

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

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

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

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

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

St. Leon LP Units

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

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

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

Office Facilities

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

Chartered Aircraft

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

Trafalgar

The Company owns debt on seven hydroelectric facilities owned by Trafalgar Power Inc. and an affiliate ("**Trafalgar**"). In 1997, Trafalgar went into default under its debt obligations and an affiliate of APMI moved to foreclose on the assets. Subsequently, Trafalgar went into bankruptcy. APUC and the affiliate of APMI have been jointly involved in litigation and in bankruptcy proceedings with Trafalgar since 2004. APMI initially funded $2.0 million in legal fees prior to 2004.

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

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

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

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

Other

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

3.5 Principal Revenue Sources

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

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

The purchase of electricity and natural gas by the company's electric distribution and natural gas distribution system is a significant revenue driver and component of operating expenses, but these costs are effectively passed through to its customers. As a result, the company uses 'net utility sales' (see non-GAAP Financial Measures) are a more appropriate measure of the results. Adjusting for the impact of these commodity costs APUC derived approximately 31.2% of its revenues from its

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

3.6 Environmental Protection

APUC's businesses encompass operations which require adherence to environmental standards imposed by regulatory bodies through licenses, permits, standards, policies and legislation. Failure to operate such businesses in strict compliance with these regulatory standards may expose them to citations, claims, clean-up costs, penalties, and loss of operating licenses and permits.

APUC has an environmental management program including environmental policies and procedures that involve long-term environmental monitoring programs, reporting, government liaison and the development and implementation of emergency action plans as related to environmental matters.

Environmental protection requirements did not have a significant financial or operational effect on APUC's capital expenditures, earnings and competitive position for the twelve months ended December 31, 2014. Moreover, other regimes that provide incentives and credits for generation of renewable energy and for carbon offsets are expected to increase the earnings and benefit the competitive position of APUC.

APUC and its subsidiaries face a number of environmental risks that are normal aspects of operating within the renewable power generation, thermal power generation and utilities business segments which have the potential to become environmental liabilities *(see Risk Factors - Environmental)*. Many of these risks are mitigated through the maintenance of adequate insurance which include property, boiler and machinery, environmental and excess liability policies.

To manage these risks responsibly, APUC has ensured that environmental and compliance departments have been established within the different subsidiaries which are responsible for monitoring all of each subsidiary's operations, ensuring all operating facilities are in compliance with environmental regulations and preparing regulatory submissions as required.

3.7 Employees

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

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

3.8 Foreign Operations

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

3.9 Economic Dependence

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

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

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

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

3.10 Social or Environmental Policies

APUC has formal policies and procedures that support its commitment to corporate responsibility. APUC's Code of Business Conduct and Ethics is the foundation of the Corporation's corporate responsibility framework. As a condition of employment, all employees are required to read the Code of Business Conduct and Ethics and apply the code to their work.

Employees are required to complete a declaration annually, which confirms their compliance with and understanding of the Code of Business Conduct and Ethics. During the course of business, any compliance exceptions are reviewed and managed promptly.

APUC's businesses have safety and environmental compliance policies in place. These policies have been communicated with staff, and have been incorporated into their respective Safety Mission Statements and Employee manuals.

APUC has an Environmental, Health and Safety Group that reports independently to the President of the appropriate region. This group is responsible for developing environmental and safety policies, developing and delivering environmental and safety training, conducting internal audits of environmental and safety performance, and arranging for third party environmental and safety audits.

APUC is actively involved in Corporate Responsibility ("**CR**"). Using the Global Reporting Initiative ("**GRI**"), the Corporation formally tracks several GRI indicators, and in 2014 began publishing a CR report. With CR as an element of the Company's decision making the Corporation reduces liability for investors, increases morale and engagement of employees, creates an environmentally cleaner community, and enhances the partnership with all of its stakeholders.

CR is often defined by a company's philosophy to operate in an economically, socially and environmentally sustainable manner, while recognizing the interests of its stakeholders. APUC has environmentally supportive programs in place that promote energy efficiency and responsible water usage, help facilitate habitat conservation to minimize impact, monitor greenhouse gas emissions, and promote waste reduction and spill prevention. The economic branch of the Corporation's CR efforts incorporates local spending, local hiring, and operational efficiency. The Corporation's commitment to people is demonstrated through our employee training, learning and development programs, organizational improvements, emergency management, health and safety policies, diversity in the workplace, and community involvement. The Corporation believes this philosophy will contribute to a sustainable future for its investors, communities, environment, customers, employees, governments, and business partners.

3.11 Credit Ratings

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

	S&P		DBRS	
	2014	2013	2014	2013
APUC - Issuer rating	BBB	BBB	BBB(low)	BBB(low)
APUC - Preferred Shares	P-3 [3]	P-3 [3]	Pfd-3 (low)	Pfd-3 (low)
APCo - Issuer rating	BBB	BBB	BBB (low)	BBB (low)
APCo - Senior unsecured debt	BBB	BBB	BBB (low)	BBB (low)
Liberty Utilities	BBB	BBB	-	-
LU GP1 - Issuer rating[2]	-	-	BBB (high)	BBB (high)
LU GP1 - Senior unsecured notes	-	-	BBB (high)	BBB (high)
CalPeco - Senior unsecured notes	-	-	BBB	BBB

[1] Credit ratings are intended to provide investors with an independent measure of the credit quality of an issue of securities. Credit ratings are not a recommendation to buy, sell or hold securities of APUC and do not comment as to market price or suitability for a particular investor. There can be no assurance that a rating will remain in effect for any given period of time or that the rating will not be revised or withdrawn at any time by the rating agency.

[2] Issued by LU Gp1 and guaranteed by Liberty Utilities.

[3] P-3 rating is equivalent to a BB rating on S&P's global preferred share rating scale

DBRS

DBRS rates debt instruments and issuers with ratings ranging from "AAA", which represents debt instruments and issuers of the highest credit quality, to "D", which represent debt instruments for which a company has not made a scheduled payment of interest or principal or has made it clear it will miss such a payment in the near future. Long-term debt rated "BBB" category by DBRS are of adequate credit quality. Protection of interest and principal is considered acceptable, but the entity is fairly susceptible to adverse changes in financial and economic conditions, or there may be other adverse conditions present which

reduce the strength of the entity and its rated securities. A DBRS rating may be modified by the addition of a "(high)" or "(low)" to indicate the relative standing within a particular rating category. The absence of either a "(high)" or "(low)" designation indicates that the rating is in the "middle" of the category.

According to the DBRS rating system, preferred shares rated Pfd-3 are of adequate credit quality. While protection of dividends and principal is still considered acceptable, the issuing entity is more susceptible to adverse changes in financial and economic conditions, and there may be other adverse conditions present which detract from debt protection. "High" or "low" grades are used to indicate the relative standing within a rating category. The absence of either a "high" or "low" designation indicates the rating is in the middle of the category

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

S&P

S&P rates debt instruments and issuers with ratings ranging from "AAA", which represent the greatest ability of an obligor to meet its financial commitment, to "D", which represents an obligor in payment default. An obligor rated 'BBB' has adequate capacity to meet its financial commitments. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments. An S&P rating may be modified by the addition of a plus "+" or minus "-" sign to show relative standing within the major rating categories. The absence of either a plus "+" or minus "-" sign indicates that the rating is in the "middle" of the category.

According to the S&P rating system, preferred shares rated P-3 are regarded as having significant speculative characteristics. While such securities will likely have some quality and protective characteristics, these may be outweighed by large uncertainties or major exposures to adverse conditions. The ratings from P-1 to P-5 may be modified by "high" and "low" grades which indicate relative standing within the major rating categories.

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

4. ENTERPRISE RISK MANAGEMENT

An enterprise risk management ("**ERM**") framework is embedded across the organization that systematically and broadly identifies, assesses, and mitigates the key strategic, operational, financial, and compliance risks that may impact the achievement of our objectives. APUC's ERM policy details the risk management processes, risk appetite, and risk governance structure which clearly establishes accountabilities for managing risk across the organization.

As part of the risk management processes, risk registers have been developed across the organization through ongoing risk identification and risk assessment exercises facilitated by APUC's internal ERM team. Key risks and associated mitigation strategies are reviewed by the Executive Risk Steering Committee on a monthly basis and presented to the Board of Directors on a quarterly basis. The key risk categories assessed include: safety, environment, natural disasters, security (physical and cyber), operations, organizational effectiveness, contracts, budget, capital projects, return on M&A activity, markets, liquidity, financial reporting, strategic, and regulatory.

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

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

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

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

4.1 Financial Risk Management

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

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

4.1.1 Market Price Risk

(i) Generation Group

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

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

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

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

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

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

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

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

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

(ii) Distribution Group

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

4.1.2 Foreign Currency Risk

Currency fluctuations may affect the cash flows APUC would realize from its consolidated operations, as certain APUC subsidiary businesses sell electricity or provide utility services in the United States and receive proceeds from such sales in U.S. dollars. Such APUC businesses also incur costs in U.S. dollars. At the current exchange rate, approximately 78% of EBITDA in 2014 and 77% of cash flow from operations is generated in U.S. dollars. APUC estimates that, on an unhedged basis, a $0.10 increase in the strength of the U.S. dollar relative to the Canadian dollar would result in a net impact on U.S. operations of approximately $22.8 million ($0.10 per share) on an annual basis.

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

4.1.3 Commodity Price Risk

(i) Generation Group

The Generation Group's exposure to commodity prices is primarily limited to exposure to natural gas price risk. The Distribution Groups is exposed to energy price risk within the Electric Systems. In this regard, a discussion of this risk is set out as follows:

- The Sanger Thermal Facility's PPA includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in an increase in net revenue by approximately $0.2 million on an annual basis.
- The Windsor Locks Thermal Facility's Energy Services Agreement includes provisions which reduce its exposure to natural gas price risk but has exposure to market rate conditions for sales above those to its primary customer. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in a decrease in net revenue by approximately $0.1 million on an annual basis.
- The Maritime region provides short-term energy requirements to various customers at fixed rates. The energy requirements of these customers are estimated at approximately 174,000 MW-hrs in fiscal 2015, of which 90,000 MW-hrs is presently contracted. While the Tinker Hydro Facility is expected to provide the majority of the energy required to service these customers, the Maritime region anticipates having to purchase approximately 80,000 MW-hrs of its energy requirements at the ISO-NE summer spot rates to supplement self-generated energy should the Maritime region be able to reach the estimated 174,000 MW-hrs. The risk associated with the expected market purchases of 80,000 MW-hrs is mitigated through the use of short-term financial energy hedge contracts which cover approximately 90% of the Maritime region's anticipated purchases during the price-volatile winter months at an average rate of approximately $65 per MW-hr. For the amount of anticipated purchases not covered by hedge contracts, each $10.00 change per MW-hr in the market prices in ISO-NE would result in a change in expense of $0.5 million on an annualized basis.

(ii) Distribution Group

The CalPeco Electric System provides electric service to the Lake Tahoe California basin and surrounding areas at rates approved by the CPUC. The CalPeco Electric System purchases the energy, capacity, and related service requirements for its customers from NV Energy via a PPA at rates reflecting NV Energy's system average costs.

The CalPeco Electric System's tariffs allow for the pass-through of energy costs to its rate payers on a dollar for dollar basis, through the ECAC mechanism, which allows for the recovery or refund of changes in energy costs that are caused by the fluctuations in the price of fuel and purchased power. On a monthly basis, energy costs are compared to the CPUC approved base tariff energy rates and the difference is deferred to a balancing account. Annually, based on the balance of the ECAC balancing account, if the ECAC revenues were to increase or decrease by more than 5%, the CalPeco Electric System's ECAC tariff allows for a potential adjustment to the ECAC rates which would eliminate the risk associated with the fluctuating cost of fuel and purchased power. The CalPeco Electric System also benefits from a revenue decoupling mechanism and a vegetation management memorandum account. The revenue decoupling mechanism decouples base revenues from fluctuations caused by weather and economic factors reducing volumetric risk for the utility. The vegetation management memorandum account

allows for the tracking and pass through of vegetation management expenses, one of the largest expenses of the utility, reducing the potential for expenses to exceed the amounts allowed for in general rates.

The Granite State Electric System is an open access electric utility allowing for its customers to procure commodity services from competitive energy suppliers. For those customers that do not choose their own competitive energy supplier, Granite State Electric System provides a Default Service offering to each class of customers through a competitive bidding process. This process is undertaken semi-annually for all customers. The winning bidder is obligated to provide a full requirements service based on the actual needs of the Granite State Electric System's Default Service customers. Since this is a full requirements service, the winning bidder takes on the risk associated with fluctuating customer usage and commodity prices. The supplier is paid for the commodity by the Granite State Electric System which in turns receives pass-through rate recovery through a formal filing and approval process with the NHPUC on a semi-annual basis. The Granite State Electric System is only committed to the winning Default Service supplier(s) after approval by the NHPUC so that there is no risk of commodity commitment without pass-through rate recovery.

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

The purchases pipeline capacity, storage and commodity from a variety of counterparties, and files with the three individual State Commissions for recovery of its transportation and commodity costs through an annual PGA filing and approval process. The Midstates Gas Systems establishes rates for its customers within the PGA filing and these rates are designed to fully recover its anticipated transportation and commodity costs. In order to minimize commodity price fluctuations, and have implemented a commodity hedging program designed to hedge approximately 25-50% of its non-storage related commodity purchases. All gains and losses associated with the hedging program are allowed to be pass-through to customers through the PGA filing and are embedded in the approved rates in said filing. Rates can be adjusted on a monthly or quarterly basis in order to account for any commodity price increase or decrease relative to the initial PGA rate, minimizing any under or over collection of its gas costs.

4.1.4 Tax Risk and Uncertainty

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

Unit Exchange Transaction

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

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

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

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

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

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

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

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

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

4.1.5 Interest Rate Risk

The majority of debt outstanding in APUC and its subsidiaries is subject to a fixed rate of interest and as such is not subject to interest rate risk. Borrowings subject to variable interest rates are as follows:

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

APUC does not actively manage interest rate risk on its variable interest rate borrowings due to the primarily short term and revolving nature of the amounts drawn. The interest rate swap, although not designated as a hedge, serves to partially offset interest rate movements against the variable pay portion of the Company's debt.

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

4.1.6 Credit/Counterparty Risk

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

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

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

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

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

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

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

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

4.1.7 Liquidity Risk

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

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

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

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

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

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

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

4.1.8 Defined Benefit Pension Plan risk

In conjunction with recent utilities acquisitions, the Company assumed defined benefit pension and OPEB plans (the "Plans") for qualifying employees in the related acquired businesses. The legacy plans of the electricity and gas utilities are non-contributory defined pension plans covering substantially all employees. Benefits are based on each employee's years of service and compensation. The Company initiated a defined benefit cash balance pension plan covering substantially all its new employees and current employees at its water utilities, under which employees are credited with a percentage of base pay plus a prescribed interest rate credit. The OPEB plans provide health care and life insurance coverage to eligible retired employees. Eligibility is based on age and length of service requirements and, in most cases, retirees must cover a portion of the cost of their coverage

APUC manages the assets in its Plans by engaging professional investment managers who operate under prescribed investment policies and procedures in respect of permitted investments and asset allocations. Future contributions to the APUC's Plans are impacted by a number of variables, including the investment performance of the plans' assets and the discount rate used to value the liabilities of the plans. If capital market returns are below assumed levels, or if discount rates decrease, APUC could be required to make contributions to its Plans in excess of those currently expected.

4.2 Operational Risk Management

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

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

4.2.1 Risks Inherent to APUC's Businesses

(i) Risk Pertaining to Power Generation

APCo's profitability could be impacted by equipment failure, the failure of a major customer to fulfill its contractual obligations under its PPA, reductions in average energy prices, a strike or lock-out at a facility and expenses related to claims or clean-up to adhere to environmental and safety standards.

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

(ii) Risks Pertaining to Water Utilities

The water distribution networks of Liberty Utilities operate under pressurized conditions within pressure ranges approved by regulators. Should a water distribution network become compromised or damaged, the resulting release of pressure could result in serious injury or death to individuals or damage to other property. Profitability could be impacted by equipment failure at a facility and expenses related to claims or clean-up to adhere to environmental and safety standards.

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

(iii) Risks Pertaining to Electric Utilities

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

(iv) Risks Pertaining to Gas Utilities

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

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

4.2.2 Asset Retirement Obligations

APUC and its subsidiaries complete periodic reviews of potential asset retirement obligations that may require recognition. As part of this process, APUC and its subsidiaries consider the contractual requirements outlined in their operating permits, leases and other agreements, the probability of the agreements being extended, the likelihood of being required to incur such costs in the event there is an option or right to require decommissioning in the agreements, the ability to quantify such expense, the timing of incurring the potential expenses as well as business and other factors which may be considered in evaluating if such obligations exist and in estimating the fair value of such obligations. Based on its assessments, APUC has recorded a liability of $13.9 million in its financial statements which was assumed in 2014 in conjunction with recent acquisitions.

(i) Generation Group

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

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

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

(ii) Distribution Group

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

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

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

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

4.2.3 Cycles and Seasonality Risk

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

4.2.4 Environmental Risks

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

(i) Generation Group

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

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

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

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

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

(ii) Distribution Group

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

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

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

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

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

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

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

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

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

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

The Distribution Group estimates the remaining undiscounted and unescalated cost of these MGP-related environmental cleanup activities will be $72.6 million which, at discount rates ranging from 2.1% to 3.4%, represents the recorded accrual of $72.3 million as of December 31, 2014. By rate orders, the Regulator provided for the recovery of actual expenditures for site investigation and remediation over a period of 7 years and accordingly, as of December 31, 2014, the Company has reflected a regulatory asset of $102.7 million for the remediation of the MGP and related sites.

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

4.2.5 Mechanical and Operational Risks

APUC's profitability could be impacted by, among other things, equipment failure, the failure of a major customer to fulfill its contractual obligations under its PPA, reductions in average energy prices, a strike or lock-out at a facility, and expenses related to claims or clean-up to adhere to environmental and safety standards.

(i) Generation Group

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

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

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

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

(ii) Distribution Group

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

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

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

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

4.2.6 Litigation risks and other contingencies

Please see "*Legal Proceedings and Regulatory Actions - Part 9. Legal Proceedings and Regulatory Actions*" for a detailed description and discussion of this risk.

4.2.7 Specific Environmental Risks

(i) Generation Group

(1) Greenhouse Gas Initiatives

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

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

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

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

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

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

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

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

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

(ii) Distribution Group

(1) Water & Waste Water Distribution Systems

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

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

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

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

(iii) Natural Gas Distribution Systems

(1) Concord MGP

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

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

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

(2) Dover MGP

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

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

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

(3) Keene MGP

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

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

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

(4) Laconia MGP & Liberty Hill Disposal Site

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

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

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

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

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

(5) Manchester MGP Site

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

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

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

(6) Nashua MGP Site

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

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

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

4.2.8 Regulatory Risk

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

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

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

(i) Condemnation Expropriation Proceedings

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

4.2.9 Regimes that Could Impact APUC

(i) Generation Group

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

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

(ii) Distribution Group

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

4.2.10 Regimes that Could Benefit APUC

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

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

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

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

4.2.11 Obligations to Serve

(i) Generation Group

The Generation Group is not subject to obligations to serve.

(ii) Distribution Group

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

4.3 Regulatory Climate and Permitting Risks

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

The Generation Group

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

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

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

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

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

Condemnation Expropriation Proceedings

The Distribution Group's electricity and natural gas distribution systems could be subject to condemnation expropriation or other methods of taking by government entities under certain conditions. While any taking by government entities would require compensation be paid to the Distribution Group, and while the Distribution Group believes it would receive fair market value for any assets that are taken, there is no assurance that the value received for assets taken will be in excess of book value. In 2014, the Company entered into an agreement to acquire the regulated water distribution utility Park Water Company. The Park Water Company owns and operates three regulated water utilities engaged in the production, treatment, storage,

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

4.4 Safety Considerations

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

4.5 Labour Relations

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

Generation Group

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

Distribution Group

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

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

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

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

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

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

4.6 Dependence Upon Key Customers

(i) Generation Group

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

(ii) Distribution Group

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

4.7 Potential Conflicts of Interest

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

4.8 Construction / Development Risk

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

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

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

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

4.9 Acquisitions and Divestitures

Acquisitions of complementary businesses and technologies are a part of APUC's overall business strategy. In spite of the complementary nature of any businesses or technologies acquired, there is always a risk that services, technologies, key personnel or businesses of acquired companies may not be effectively assimilated into APUC's business or service offerings. Similarly, divestitures of businesses that are no longer viewed as being strategic to APUC's continuing operations can be an active part of APUC's overall business strategy. Divestitures may result in a reduction in total revenues and net income.

APCo and Liberty Utilities each have a transition management office ("**TMO**") that have developed standard project management and governance processes to manage its respective company integrations due to acquisitions. These processes ensure an effective organization of people, resources and time frames for a successful integration of technology, operations, asset management and business processes. The TMO uses a sound governance reporting structure which includes the participation of the Generation and Distribution Groups' senior management to ensure that the respective operations and processes are implemented in a timely and efficient manner. The governance process also includes a transparent issue resolution process which is documented and reported throughout the Generation and Distribution Groups.

5. DIVIDENDS

Common Shares

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

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

The Board has adopted a dividend policy to provide sustainable dividends to shareholders, considering cash flow from operations, financial condition, financial leverage, working capital requirements and investment opportunities. The Board can modify the dividend policy from time to time at its discretion. There are no restrictions on the dividend policy of APUC. The amount of dividends declared and paid is ultimately dependent on a number of factors, including the risk factors previously noted. See "*Risk Factors*".

Preferred Shares

On November 9, 2012, APUC issued 4,800,000 Series A Shares. For an initial six year period the holders of Series A Shares are entitled to receive fixed cumulative preferential cash dividends, as and when declared by the Board, payable quarterly on the last business day of March, June, September and December in each year at an annual rate equal to $1.1250 per Series A Share. In 2012, 2013 and 2014, dividends paid to Series A Share holders totalled $0.8 million, $5.4 million, and $5.4 million.

On January 1, 2013, the Corporation issued 100 redeemable Series C preferred shares and exchanged such shares for the 100 Class B units of St. Leon LP, including 36 units held indirectly by the Senior Management. The Series C preferred shares provide dividends essentially identical to that expected from the Class B units. In 2013 and 2014, dividends paid to Series C preferred shareholders totalled $0.9 million and $0.9 million.

On March 5, 2014, APUC issued 4,000,000 Series D Shares. For an initial five year period the holders of Series D Shares are entitled to receive fixed cumulative preferential cash dividends, as and when declared by the Board, payable quarterly on the last business day of March, June, September and December in each year at an annual rate equal to $1.250 per Series D Share. In 2014, dividends paid to Series D Shareholders totalled $4.1 million.

5.1 Dividend Reinvestment Plan

Effective October 1, 2011, APUC introduced a shareholder dividend reinvestment plan (the "**Reinvestment Plan**") which is offered to registered holders of Common Shares.

The purpose of the Reinvestment Plan is to enable Shareholders to invest cash dividends paid on Common Shares in additional Common Shares ("**Plan Shares**"). All such Plan Shares will be, at APUC's election, either (i) Common Shares purchased on the open market through the facilities of the TSX ("**Market Purchase**") or (ii) newly issued Common Shares purchased from treasury ("**Treasury Purchase**").

The price at which Plan Shares will be purchased with such cash dividends will be (i) in the case of a Market Purchase, the volume weighted average price paid (excluding brokerage commissions, fees and transaction costs) per Plan Share by the agent for all Plan Shares purchased in respect of a dividend payment date under the Reinvestment Plan, or (ii) in the case of a Treasury Purchase, the volume weighted average of the trading price for Common Shares on the TSX for the five trading days immediately preceding the relevant dividend payment date less a discount, if any, of up to five percent (5%), at APUC's election. No commissions, service charges or brokerage fees are payable by shareholders in connection with the Reinvestment Plan.

As at December 31, 2014, 63,839,443 Common Shares had been registered with the Reinvestment Plan.

6. DESCRIPTION OF CAPITAL STRUCTURE

6.1 Common Shares

APUC may issue an unlimited number of Common Shares. The holders of Common Shares are entitled to dividends, if and when declared; to one vote for each Common Share at meetings of the holders of Common Shares; and to receive a pro rata share of any remaining property and assets of APUC upon liquidation, dissolution or winding up of APUC. All Common Shares are of the same class and with equal rights and privileges and are not subject to future calls or assessments.

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

6.2 Private Placements of Subscription Receipts and Common Shares to Emera

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

Subscription Receipts

On October 7, 2014, the Company issued 8,708,170 Subscription Receipts of APUC at a purchase price of $8.90 per Subscription Receipt for an aggregate subscription price of $77.5 million. The investment was made under the Strategic Investment Agreement between Emera and APUC, in support of the acquisition by APUC of the Odell Wind Project in Minnesota

(the "**Odell Acquisition**"). The proceeds of the subscription are intended to be used by APUC to partially finance the Odell Acquisition and the completion of the Odell Wind Project. Subject to adjustments as provided in the applicable subscription agreement, Emera may convert the Subscription Receipts into common shares of APUC on a one-for-one basis on November 14, 2015 (the first anniversary of the closing of the Odell Acquisition) or the commercial operation date of the Odell Wind Project, whichever is first to occur.

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

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

Common Shares

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

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

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

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

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

6.3 Preferred Shares

APUC is also authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board.

On November 9, 2012, APUC issued 4.8 million Series A Shares at a price of $25 per share, for aggregate gross proceeds of $120 million. The Series A Shares yield 4.5% per cent annually for the initial six-year period ending on December 31, 2018. The Series A Shares have been assigned a rating of P-3 and Pfd-3(low) by S&P and DBRS respectively. The proceeds of the offering were used primarily to partially fund the acquisition of the U.S Wind Portfolios interests which closed on December 10, 2012. The Series A Shares are convertible in certain circumstances into cumulative floating rate preferred shares, Series B (the "**Series B Shares**").

On January 1, 2013, APUC issued an aggregate of 100 Series C preferred shares to the holders of the Class B units of St. Leon LP, in exchange for such Class B units. (See "Description of the Business – Business Associations with APMI and Senior Executives - St Leon LP Units".)

On March 5, 2014, APUC issued 4.0 million Series D Shares at a price of $25 per share, for aggregate gross proceeds of $100 million. The Series D Shares yield 5.0% annually for the initial five-year period ending March 31, 2019. The preferred shares have been assigned a rating of P-3 (High) and Pfd-3 (Low) by S&P and DBRS respectively. The net proceeds of the offering were used to partially finance certain of APUC's previously disclosed growth opportunities, reduce amounts outstanding on APUC's credit facilities and for general corporate purposes. The Series D Shares are convertible in certain circumstances into cumulative floating rate preferred shares, Series E (the "**Series E Shares**").

Subject to applicable corporate law, the outstanding preferred shares are non-voting and not entitled to receive notice of any meeting of shareholders, except that the Series A Shares and Series D Shares (and the Series B Shares and Series E Shares, respectively, into which they are convertible) will be entitled to one vote per share if the Corporation shall have failed to pay eight quarterly dividends on such shares. The terms of the outstanding preferred shares do not contain a right to participate in a take-over bid of the common shares of the Corporation.

As at December 31, 2014, APUC had 4.8 million Series A Shares, 100 Series C Shares, and 4.0 million Series D Shares outstanding.

6.4 Convertible Debentures

6.4.1 Series 2A Debentures

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

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

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

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

6.4.2 Series 3 Debentures

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

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

6.5 Employee Share Purchase Plan

APUC has an employee share purchase plan ("**ESPP**") in place that provides eligible employees the opportunity to have a portion of their earnings withheld to be used to purchase Common Shares. For employees resident in Canada, APUC will match up to 20% of an employee's contribution amount for the first $5,000 contributed annually and 10% of an employee's contribution amount for contributions over $5,000 and up to $10,000 annually. For employees resident in the United States, APUC will match 15% of an employee's contribution amount up to $10,000 annually. Shares purchased through the APUC matched portion vest over a one year period. At APUC's option, the shares may be (i) issued to participants from treasury at the weighted average share price at the time of issue or (ii) acquired on behalf of participants by purchases through the facilities of the TSX by an independent broker. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares. For the year ended December 31, 2014, APUC issued 93,598 shares under the ESPP and recorded $0.1 million in compensation expense.

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

6.6 Directors Deferred Share Units

Under the Company's Deferred Share Unit Plan, non-employee directors of the Company may elect annually to receive all or any portion of their compensation in Deferred Share Units ("DSUs") in lieu of cash compensation. Directors' fees are paid on a quarterly basis and at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one of the Company's common share. Dividends accumulate in the DSU account and are converted to DSUs based on the market value of the shares on that date. DSUs cannot be redeemed until the Director retires, resigns, or otherwise leaves the Board. The DSUs provide for settlement in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards. For the year ended December 31, 2014, APUC issued 35,455 DSUs under the Deferred Share Unit Plan.

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

6.7 Performance Share Units

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

The PSUs have a three year vesting period, after which the number of shares vested can range from 0% to 184% of the number of PSUs granted. Dividends accumulate during vesting periods are converted to PSUs based on the market value of the shares on that date. None of the PSUs have voting rights. Any PSUs not vested at the end of a performance period will expire. The PSUs provide for settlement in cash or shares at the election of APUC. At the annual general meeting held on June 18, 2014, the shareholders approved a maximum of 500,000 shares issuable from Treasury to settle PSUs. With the ability to issue shares from Treasury or purchase shares on the market, the Company expects to settle the remaining PSUs in shares. As a result, the PSUs continue to be accounted for as equity awards.

Compensation expense associated with PSUs is recognized rateably over the performance period based on APUC's estimated achievement of the established metrics. Compensation expense for awards with performance conditions will only be recognized for those awards for which it is probable that the performance conditions will be achieved and which are expected to vest. The compensation expense will be estimated based upon an assessment of the probability that the performance metrics will be achieved and anticipated vesting percentage. During the year, the Company issued 407,962 PSUs to executives and employees of the Company.

As at December 31, 2014, a total of 440,086 PSU's have been granted and outstanding under the PSU plan.

6.8 Shareholders' Rights Plan

The shareholders' rights plan (the "**Rights Plan**") is designed to ensure the fair treatment of shareholders in any transaction involving a potential change of control of APUC and will provide the Board and shareholders with adequate time to evaluate any unsolicited take-over bid and, if appropriate, to seek out alternatives to maximize shareholder value. An Amended and Restated Rights Plan was approved by shareholders at the annual and special meeting of shareholders of APUC held in 2013.

Until the occurrence of certain specific events, the rights will trade with the Common Shares of APUC and be represented by certificates representing the Common Shares. The rights become exercisable only when a person, including any party related to it or acting jointly with it, with the exception of Emera, acquires or announces its intention to acquire twenty percent or more of the outstanding Common Shares without complying with the permitted bid provisions of the Plan. The application of the Rights Plan to acquisition of Common Shares by Emera under allowed transactions was waived following shareholder approval at the annual and special meeting of shareholders held on June 21, 2010. Should a non-permitted bid be launched,

each right would entitle each holder of shares (other than the acquiring person and persons related to it or acting jointly with it) to purchase additional Common Shares at a fifty percent discount to the market price at the time.

It is not the intention of the Rights Plan to prevent take-over bids but to ensure their proper evaluation by the market. Under the Rights Plan, a permitted bid is a bid made to all shareholders for all of their Common Shares on identical terms and conditions that is open for no less than 60 days. If at the end of 60 days at least fifty percent of the outstanding Common Shares, other than those owned by the offeror and certain related parties, have been tendered and not withdrawn, the offeror may take up and pay for the Common Shares but must extend the bid for a further ten days to allow all other shareholders to tender.

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

The Amended and Restated Rights Plan will remain in effect until the termination of the annual meeting of the shareholders of APUC in 2016 or its termination under the terms of the of Amended and Restated Rights Plan. The Amended and Restated Rights Plan is similar to rights plans adopted by many other Canadian corporations.

6.9 Stock Option Plan

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

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

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

In addition, under the Stock Option Plan:

- subject to the terms of the Stock Option Plan, the number of Common Shares subject to each Option, the exercise price of each Option, the expiration date of each Option, the extent to which each Option vests and is exercisable from time to time during the term of the Option and other terms and conditions relating to each Option will be determined by the Board from time to time;
- subject to any adjustments pursuant to the provisions of the Stock Option Plan, the exercise price of any Option shall in no circumstances be lower than the Market Price (as defined below) of the Common Shares on the date on which the Board approves the grant of the Option;
- Options will be personal to the grantee and will be non-transferable and non-assignable, except in certain limited circumstances;
- the maximum number of Common Shares which may be reserved for issuance to insiders under the Stock Option Plan, together with the number of Common Shares reserved for issuance to insiders under any other securities based compensation arrangement, shall be 10% of the Common Shares outstanding at the time of the grant;
- the maximum number of Common Shares which may be issued to insiders under the Stock Option Plan and all other security based compensation arrangements within a one year period shall be 10% of the Common Shares outstanding at the time of the issuance;

- non-employee director participation in the Stock Option Plan is limited to the lesser of (i) a reserve of 1% of the Common Shares outstanding for non-employee directors as a group and (ii) an annual equity award value of $100,000 per director;
- if the expiration date for an Option occurs during a Blackout Period (as defined below) or within 10 business days after the expiry date of a Blackout Period applicable to a person granted Options (an "**Optionee**"), then the expiration date for that option will be extended to the 10th business day after the expiry date of the Blackout Period. A "**Blackout Period**" is a period of time of time during which the Optionee cannot exercise an Option, or sell Common Shares issuable pursuant to the exercise of Options, due to applicable policies of the Corporation in respect of insider trading); and
- except in certain circumstances, the term of an Option shall not exceed ten (10) years from the date of the grant of the Option.

Under the Stock Option Plan, "**Market Price**" of the Common Shares is defined as the volume weighted average trading price of such Common Shares on the TSX (or, if such Common Shares are not then listed and posted for trading on the TSX, on such stock exchange in Canada on which such Common Shares are listed and posted for trading as may be selected for such purpose by the Board) for the five consecutive trading days immediately preceding such date, provided that in the event that such Common Shares did not trade on any of such trading days, the Market Price will be the average of the bid and ask prices in respect of such Common Shares at the close of trading on all of such trading days and provided that in the event that such Common Shares are not listed and posted for trading on any stock exchange, the Market Price will be the fair market value of such Common Shares as determined by the Board in its sole discretion.

The Stock Option Plan provides that, except as set out in the Stock Option Plan or any resolution passed at any time by the Board or the terms of any option agreement or employment agreement with respect to any Option or an Optionee, an Option and all rights to purchase Common Shares pursuant thereto shall expire and terminate immediately upon the Optionee who holds such Option ceasing to be an Eligible Person.

Where an Optionee (other than a service provider) resigns from the Corporation or is terminated by the Corporation for cause, the Optionee's unvested options shall immediately be forfeited and the Optionee's vested options may be exercised for a period of 30 days after the date of resignation or termination.

Where an Optionee (other than a service provider) retires from the Corporation or ceases to serve the Corporation or an affiliate as a director, officer or employee for any reason other than a termination by the Corporation for cause, the Optionee's unvested options may be exercised within 90 days after such retirement or termination. The Board may in such circumstances accelerate the vesting of unvested Options then held by the Optionee at the Board's discretion.

In the event that an Optionee, other than a service provider, has suffered a permanent disability, Options previously granted to such Optionee shall continue to vest and be exercisable in accordance with the terms of the grant and the provisions of the Stock Option Plan, but no additional grants of Options may be made to the Optionee.

If an Optionee, other than a service provider, dies, all unexercised Options held by such Optionee at the time of death immediately vest, and such Optionee's personal representatives or heirs may exercise all Options within one year after the date of such death.

All Options granted to service providers shall terminate in accordance with the terms, conditions and provisions of the associated option agreement between the Corporation and such service providers, provided that such termination shall occur no later than the earlier of (i) the original expiry date of the term of the Option and (ii) one year following the date of termination of the engagement of the service provider.

Options may be exercised in accordance with the specific terms of their grant and by the Optionee delivering the exercise price to the Corporation for all of the Options exercised. The Optionee may also surrender Options and receive in exchange for each such Option, the amount by which the Market Price of the Common Shares exceeds the exercise price of the Option (the "**In-the-Money Amount**"). If the Optionee elects to surrender any Options in exchange for the In-the-Money Amount, the Corporation will determine whether to pay such amount in cash or in Common Shares representing the equivalent of the In-the-Money Amount based on the Market Price of the Common Shares at the date of exercise, in each case net of an amount equal to any withholding taxes.

In the event that the Common Shares are at any time changed or affected as a result of the declaration of a stock dividend, a Common Share subdivision or consolidation, the number of Common Shares reserved for Options shall be adjusted accordingly by the Board to such extent as it deems proper in its discretion.

If, after the grant of an Option and prior to its expiry:

(i) the Common Shares are reclassified, reorganized or otherwise changed (a "**Share Reorganization**"), otherwise than as specified in the immediately preceding paragraph, or

(ii) subject to the Corporation's right to allow the exercise of vested and unvested Options following the occurrence of certain transactions, the Corporation shall consolidate, merge or amalgamate with or into another corporation (a "**Merger**", with the resulting corporation being the "**Successor Corporation**"),

the Optionee will receive, upon the subsequent exercise of his or her Options in accordance with the Stock Option Plan, the number of Common Shares or securities of the appropriate class of the Corporation or Successor Corporation, as the case may be, that the Optionee would have received if on the record date of such Share Reorganization or Merger the Optionee were the registered holder of the number of Common Shares to which the Optionee was prior thereto entitled to receive on exercise of his or her Options.

The Board may amend, suspend or discontinue the Stock Option Plan or amend Options granted under the Stock Option Plan at any time without shareholder approval; provided, however, that:

(a) approval by a majority of the votes cast by shareholders present and voting in person or by proxy at a meeting of shareholders of the Corporation shall be obtained for the following amendments:

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

  (ii) reduction of the exercise price, or cancellation and reissuance of Options or other entitlements, of non-insider Options granted under the Stock Option Plan;

  (iii) extension of the term of Options beyond the original expiry date of non-insider Options;

  (iv) change in Eligible Participants that may permit an increase to the limit imposed on non-employee director participation;

  (v) permitting of Options granted under the Stock Option Plan to be transferable or assignable other than for estate settlement purposes; or

  (vi) amendment to the Stock Option Plan's amendment provisions; and

(b) the consent of the Optionee is obtained for any amendment which alters or impairs any Option previously granted to an Optionee under the Stock Option Plan.

Notwithstanding the other provisions of the Stock Option Plan, if:

(a) the Corporation proposes to amalgamate, merge or consolidate with any other corporation (other than a wholly-owned affiliate) or to liquidate, dissolve or wind-up;

(b) an offer to purchase or repurchase all of the Common Shares shall be made to all holders of Common Shares which offer has been approved or accepted by the Board; or

(c) the Corporation proposes the sale of all or substantially all of the assets of the Corporation as an entirety, or substantially as an entirety, so that the Corporation shall cease to operate any active business,

then, the Corporation will have the right, upon written notice thereof to Optionees, to permit the exercise of all such Options, whether or not vested, within the 20 day period next following the date of such notice and to determine that upon the expiration of such 20 day period, all rights of the Optionee to such Options or to exercise same (to the extent not theretofore exercised) shall *ipso facto* terminate and cease to have further force or effect whatsoever.

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

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

7. MARKET FOR SECURITIES

7.1 Trading Price and Volume

7.1.1 Common Shares

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

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

7.1.2 Preferred Shares

Series A Shares

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

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

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

Series D Shares

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

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

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

7.2 Prior Sales

During the year ended December 31, 2010, 1,160,205 options were granted to senior executives of APUC which allow for the purchase of Common Shares at a price of $4.05 per share. One-third of the options vested on each of January 1, 2011, 2012 and 2013.

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

- On March 22, 2011, 892,107 options were granted to senior executives of APUC which allow for the purchase of Common Shares at a price of $5.23 per share;
- On June 21, 2011, 171,642 options were granted to a senior executive of APCo which allow for the purchase of Common Shares at a price of $5.64 per share;
- On July 28, 2011, 90,909 options were granted to a senior executive of APUC which allow for the purchase of Common Shares at a price of $5.74 per share; and
- On September 13, 2011, 172,242 options were granted to a senior executive of Liberty Utilities which allow for the purchase of Common Shares at a price of $5.65 per share.

In each case, one-third of the options vested on each of January 1, 2012, 2013, and 2014.

On March 14, 2012, 1,194,606 options were granted to senior executives of APUC and senior managers which allow for the purchase of Common Shares at a price of $6.22 per share. One-third of the options vest on each of January 1, 2013, 2014 and 2015.

On June 19, 2012, 69,016 options were granted to senior executives of APUC and senior managers which allow for the purchase of Common Shares at a price of $6.56 per share. One-third of the options vest on each of January 1, 2013, 2014 and 2015.

On March 14, 2013, 816,402 options were granted to senior executives of APUC and senior managers which allow for the purchase of Common Shares at a price of $7.72 per share. One-third of the options vest on each of January 1, 2014, 2015, and 2016.

On May 13, 2014, 969,998 options were granted to senior executives of APUC and senior managers which allow for the purchase of Common Shares at a price of $7.95 per share. One-third of the options vest on each of January 1, 2015, 2016, and 2017.

All options were issued using the five day volume weighted average price of the underlying Common Shares at the date of the grant. In all cases, options may be exercised up to eight years following the date of grant. During the year ended December 31, 2014, no options were exercised. As at December 31, 2014, APUC had 5,537,127 options issued and outstanding. As at December 31, 2014, 3,601,647 options were exercisable. No options were exercised in 2014 or 2013 or 2012.

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

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

7.3 Escrowed Securities and Securities Subject to Contractual Restrictions on Transfer

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

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

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

8. DIRECTORS AND OFFICERS

8.1 Name, Occupation and Security Holdings

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

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from
CHRISTOPHER J. BALL Toronto, Ontario, Canada Age: 64	Christopher Ball is the Executive Vice President of Corpfinance International Limited, and President of CFI Capital Inc., both of which are investment banking boutique firms. From 1982 to 1988, Mr. Ball was Vice President at Standard Chartered Bank of Canada with responsibilities for the Canadian branch operation. Prior to that, Mr. Ball held various managerial positions with the Canadian Imperial Bank of Commerce. He is also a member of the Hydrovision International Advisory Board, was a director of Clean Energy BC, and is a recipient of the Clean Energy BC Lifetime Achievement Award.	Director of APUC since October 27, 2009. Trustee of APCo since October 22, 2002
LINDA BEAIRSTO Oakville, Ontario, Canada Age: 54	Ms. Beairsto has been Chief General Counsel and Corporate Secretary for APUC since June 2011. Previously, she held various diverse roles including Commercial Real Estate Lawyer at Fasken Martineau, Special Counsel at E.I. du Pont Canada Inc., Director of Legal Services at Patheon Inc., Executive Vice-President & Chief Legal Counsel at ABC Group of Companies and Special Counsel at Allergan Inc. Ms. Beairsto earned a Bachelor of Arts Degree from the University of British Columbia and a Bachelor of Laws Degree from the University of New Brunswick. She was called to the Ontario Bar in 1990. In 2013, Ms. Beairsto completed the Chartered Director program of the Directors College (McMaster University) and has the certification of Ch. Dir. (Chartered Director).	Officer of APUC since June 6, 2011
DAVID BRONICHESKI Oakville, Ontario, Canada Age: 55	Mr. Bronicheski is the Chief Financial Officer ("**CFO**") of APUC. He has held various senior management positions including Executive Vice President and CFO of a publicly traded income trust providing local telephone, cable television and internet service. He was also CFO for a large public hospital in Ontario. Mr. Bronicheski holds a Bachelor of Arts in economics (cum laude), a Bachelor of Commerce degree and an MBA (University of Toronto, Rotman School of Management). He is also a Chartered Accountant and a Chartered Professional Accountant.	Officer of APUC since October 27, 2009. Officer of APCo since September 17, 2007
CHRISTOPHER HUSKILSON Wellington, Nova Scotia, Canada Age: 57	Christopher Huskilson has been the President and Chief Executive Officer of Emera, a North American energy and services company, since November 2004. He is also Chair of Emera Maine, a Director of Nova Scotia Power Inc. and serves as the Chair or as a Director of a number of other Emera affiliated companies. Mr. Huskilson has held a number of positions within Nova Scotia Power Inc. and its predecessor, Nova Scotia Power Corporation, since June 1980. Mr. Huskilson holds a Bachelor of Science in Engineering and a Master of Science in Engineering from the University of New Brunswick.	Director of APUC since October 27, 2009. Trustee of APCo since July 27, 2009
CHRISTOPHER K. JARRATT Oakville, Ontario, Canada Age: 56	Christopher Jarratt has over 25 years of experience in the independent electric power and utility sectors. Mr. Jarratt is a founder and principal of Algonquin Power Corporation Inc., a private independent power developer formed in 1988 which is the predecessor organization to APCo and APUC. Between 1997 and 2009, Mr. Jarratt was a principal in Algonquin Power Management Inc. which managed APCo (formerly Algonquin Power Income Fund). Since 2010, Mr. Jarratt has been a board member and served as Vice Chair of APUC. Prior to 1988, Mr. Jarratt was a founder and principal of a consulting firm specializing in renewable energy project development and environmental approvals. Mr. Jarratt earned an Honours Bachelor of Science degree from the University of Guelph in 1981 specializing in water resources engineering and holds an Ontario Professional Engineering designation. In 2009, Mr. Jarratt completed the Chartered Director program of the Directors College (McMaster University) and holds the certification of Ch. Dr. (Chartered Director). In addition, Mr. Jarratt was co-recipient of the 2007 Ernst & Young Entrepreneur of the Year finalist award.	Director of APUC since June 23, 2010.

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from
KENNETH MOORE Toronto, Ontario, Canada Age: 56	Kenneth Moore is the Managing Partner of NewPoint Capital Partners Inc., an investment banking firm. From 1993 to 1997, Mr. Moore was a senior partner at Crosbie & Co., a Toronto mid-market investment banking firm. Prior to investment banking, he was a Vice-President at Barclays Bank where he was responsible for a number of leveraged acquisitions and restructurings. Mr. Moore holds a Chartered Financial Analyst designation. Additionally, he has completed the Chartered Director program of the Directors College (McMaster University) and has the certification of Ch. Dir. (Chartered Director).	Director of APUC since October 27, 2009. Trustee of APCo since December 18, 1998
DAVID PASIEKA Oakville, Ontario, Canada Age: 58	David Pasieka is the President of APUC's Distribution Business Group. As President, Mr. Pasieka is focused on acquiring and managing a portfolio of regulated water, natural gas and electrical companies throughout the United States. The focus of the portfolio is in the distribution, transmission, and generation sectors. Mr. Pasieka has global experience in strategy, sales, marketing, integration, operations and customer service. He has led many organizations while integrating people, process and technology to encourage the steady growth of the organizations. Mr. Pasieka holds a Bachelor of Science Degree from the University of Waterloo, Masters of Business Administration from the Schulich School of Business –York University and a Chartered Director designation from McMaster University.	President - Liberty Utilities (Canada) Corp. since September 1, 2011
IAN E. ROBERTSON Oakville, Ontario, Canada Age: 55	Ian Robertson is the Chief Executive Officer of the Corporation. Mr. Robertson is a founder and principal of Algonquin Power Corporation Inc., a private independent power developer formed in 1988 which was a predecessor organization to APUC. Mr. Robertson has over 23 years of experience in the development of electric power generating projects and the operation of diversified regulated utilities. Mr. Robertson is an electrical engineer and holds a Professional Engineering designation through his Bachelor of Applied Science degree awarded by the University of Waterloo. Mr. Robertson earned a Master of Business Administration degree from York University and holds a Chartered Financial Analyst designation. Additionally, he has completed the Chartered Director program of the Directors College (McMaster University) and has the certification of Ch. Dir. (Chartered Director). Commencing in 2013, Mr. Robertson has served on the Board of Directors of the American Gas Association.	Director of APUC since June 23, 2010.
MASHEED SAIDI Dana Point, California, United States Age: 60	Masheed Saidi has over 30 years of operational and business leadership experience in the electric utility industry. Ms. Saidi is an Executive Consultant of Energy Initiatives Group, a specialized group of experienced professionals that provide technical, commercial and business consulting services to utilities, ISOs, government agencies and other organizations in the energy industry. Between 2005 and 2010, Ms. Saidi was the Chief Operating Officer and Executive Vice President of US Transmission for National Grid USA, for which she was responsible for all aspects of US transmission business. Ms. Saidi previously served on the Board of Directors on the Northeast Energy and Commerce Association. She serves as Chairman of the Board of Directors for the non-profit organization Mary's Shelter. She earned her Bachelors in Power System Engineering from Northeastern University and her Masters of Electrical Engineering from the Massachusetts Institute of Technology. She is a Registered Professional Engineer (P.E.)	Director of APUC since June 18, 2014
DILEK SAMIL Las Vegas, Nevada, United States Age: 59	Dilek Samil has over 30 years of finance, operations and business experience in both the regulated energy utility sector as well as wholesale power production. Ms. Samil joined NV Energy as Chief Financial Officer and retired as Executive Vice President and Chief Operating Officer. While at NV Energy, Ms. Samil completed the financial transformation of the company bringing its financial metrics in line with those of the industry. As Chief Operating Officer, Ms. Samil focused on enhancing the company's safety and customer care culture. Prior to her role at NV Energy, Ms. Samil gained considerable experience in generation and system operations as President and Chief Operating Officer for CLECO Power. During her tenure at CLECO, the company completed construction of its largest generating unit and successfully completed its first rate case in over 10 years. Ms. Samil also served as CLECO's Chief Financial Officer at a time when the industry and the company faced significant turmoil in the wholesale markets. She led the company's efforts in the restructuring of its wholesale and power trading activities. Prior to NV Energy and Cleco, Ms. Samil spent about 20 years at NextEra where she held positions of increasing responsibility, primarily in the finance area. Ms. Samil holds a Bachelor of Science from the City College of New York and a Masters of Business Administration from the University of Florida.	Director of APUC since October 1, 2014

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from
MIKE SNOW Markham, Ontario, Canada Age: 54	Mike Snow is the President of APUC's Generation Business Group and is responsible for all aspects of strategy, business development, operations, asset management, human resources, and evaluating and reporting on growth and operational activities. Mr. Snow has led both industrial and consumer organizations focused on growth and international operations in Mexico, South America, and Asia, while driving culture change and building strong leadership teams. Mike holds a Bachelor of Science Degree in Math from Dalhousie University, a Bachelor of Engineering Degree (Mechanical) from the Technical University of Nova Scotia, and a Masters of Business Administration from the Richard Ivey School of Business – University of Western Ontario.	Officer of APUC since July 4, 2011
GEORGE L. STEEVES Aurora, Ontario, Canada Age: 65	George Steeves is the principal of True North Energy, an energy consulting firm specializing in the provision of technical and financial due diligence services for renewable energy projects. From January 2001 to April 2002, Mr. Steeves was a division manager of Earthtech Canada Inc. Prior to January 2001, he was the President of Cumming Cockburn Limited, an engineering firm, and has extensive financial expertise in acting as a chair, director and/or audit committee member of public and private companies, including the Corporation, and formerly Borealis Hydroelectric Holdings Inc. and KMS Power Income Fund. Mr. Steeves received a Bachelor and Masters of Engineering from Carleton University and holds the Professional Engineering designation in Ontario and British Columbia. Additionally he has completed the Chartered Director program of the Directors College (McMaster University) and has the certification of Ch. Dir. (Chartered Director).	Director of APUC since October 27, 2009. Trustee of APCo since September 8, 1997
GEORGE TRISIC Oakville, Ontario, Canada Age: 54	George Trisic is the Senior Vice President of Business Services for the Corporation, and has broad experience managing in high growth, start up and expanding businesses across multiple sites and regions. In his role, Mr. Trisic is responsible for shared services for the Corporation including information technology, human resources, communications, legal, and procurement, and is a well-regarded team builder and business partner. His skill set includes leading multi-functional groups in finance, human resources, legal, and information technology in a senior role. Mr. Trisic earned a Bachelor of Law Degree from the University of Western Ontario in 1984.	Officer of APUC since November 4, 2013

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

As at March 30, 2015, the directors and executive officers of Algonquin, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 987,442 Common Shares, representing less than one percent of the total number of Common Shares outstanding before giving effect to the exercise of options or warrants to purchase Common Shares held by such directors and executive officers. The statement as to the number of Common Shares beneficially owned, directly or indirectly, or over which control or direction is exercised by the directors and executive officers of Algonquin as a group is based upon information furnished by the directors and executive officers.

8.2 Audit Committee

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

8.2.1 Audit Committee Charter

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

8.2.2 Relevant Education and Experience

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

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

Mr. Moore has extensive financial experience and is the Managing Partner of NewPoint Capital Partners Inc., a boutique financial advisory firm focused on mergers and acquisitions. He was formerly a Vice-President at a Canadian Chartered Bank. Mr. Moore has completed the Chartered Director program of the Directors College (McMaster University and the Conference Board) and has the designation of Ch. Dir. (Chartered Director)

Ms. Samil has extensive financial experience, with over 30 years of finance, operations and business experience in the regulated energy utility sector. During her career, Ms. Samil was the Executive Vice President and Chief Operating Officer of NV Energy, Inc. and gained considerable experience in generation and system operations as President and Chief Operating Officer for CLECO Power LLC. Ms. Samil holds a Bachelor of Science from the City College of New York and a Masters of Business Administration from the University of Florida.

8.2.3 Pre-Approval Policies and Procedures

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

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

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

1 For professional services rendered for audit or review or services in connection with statutory or regulatory filings or engagements.

2 For assurance and related services that are reasonably related to the performance of the audit or review of the Corporation's financial statements and not reported under Audit Fees, including audit procedures relate to regulatory commission filings and the audit of defined benefit pension plans.

3 For preparation of income and other tax filings.

4 For tax advisory and planning services.

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

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

8.3 Corporate Governance and Compensation Committees

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

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

8.4 Bankruptcies

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

David Pasieka, the President of Liberty Utilities Co., was a director of Luxell Technologies Inc. when it filed a proposal under the Bankruptcy and Insolvency Act (Canada) on September 27, 2006. Luxell Technologies Inc. received a Certificate of Full Performance of Proposal under such legislation through a letter issued by its trustee in bankruptcy on January 14, 2008.

8.5 Potential Material Conflicts of Interest

Other than as set out below or disclosed elsewhere in this AIF (including Section 3.4, Business Associations with APMI and Senior Executives) and APUC's financial statements and management's discussion and analysis for the fiscal year ended December 31, 2014, APUC is not aware of any existing or potential material conflicts of interest between APUC or a subsidiary and any current director or officer of APUC or a subsidiary. Mr. Huskilson is a director of APUC but is also the President and CEO of Emera. Emera is a major shareholder of APUC. Emera has a strategic relationship with APUC, see "*Material Contracts*". Mr. Huskilson does not vote in Board meetings on matters involving APUC's relationship with Emera nor on matters involving a potential conflict between APUC and Emera.

9. LEGAL PROCEEDINGS AND REGULATORY ACTIONS

9.1 Legal Proceedings

Except as disclosed elsewhere in this AIF, the only legal proceedings involving APUC or its subsidiaries that were material in 2014 are as follows:

(i) Trafalgar proceedings

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

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

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

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

(ii) Côte Ste-Catherine Water Lease Dues

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

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

(iii) Long Sault Global Adjustment Claim

In December 2012, N-R Power and Energy Corporation, Algonquin Power (Long Sault) Partnership, and N-R Power Partnership ("**Long Sault**") commenced proceedings (together with the other similarly affected non-utility generators) against the OEFC relating to the OEFC's interpretation of certain provisions of a PPA between Long Sault and the OEFC, in relation to the use of the global adjustment ("GA") as a price escalator. As a result of the OEFC's application of the new GA calculation to the calculation of total market cost of electricity ("**TMC**") of and, in turn, an index derived from TMC, the rate OEFC has paid to Long Sault under the PPA beginning with the application of OEFC's new TMC calculation in July 2011 has not escalated as contemplated in the PPA and term sheet. A Notice of Application was issued at the end of December 2012 with supporting materials filed at the end of April 2013. The Application was heard in May 2014. On March 12, 2015, the Ontario Superior Court of Justice ruled that the methodology that the OEFC used from January 1, 2011 onward to calculate payments under Long Sault's PPA, and those of other producers, did not comply with the terms of those PPAs. The decision further requires the OEFC to revert to its pre-2011 methodology for calculating payments and to pay producers the difference between the payments calculated by the OEFC since 2011 and the amount of the payments they would have received using the pre-2011 methodology, plus interest and costs. The OEFC has until April 13, 2015 to appeal this decision.

(iv) Dimos and Katsekas breach of contract claim

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

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

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

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

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

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

(vii) Bryson School District in Texas Property Taxes Claim

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

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

9.2 Regulatory Actions

Except as disclosed elsewhere in this AIF, during the financial year ended December 31, 2014, there have been:

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

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

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

10. INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as disclosed elsewhere in this AIF, and as disclosed in APUC's annual financial statements and management's discussion and analysis as at and for the periods ended December 31, 2014, 2013 and 2012, management has no material interest, direct or indirect, in any transaction occurring within the three most recently completed financial years or during the current financial year that has materially affected or will materially affect APUC.

11. TRANSFER AGENTS AND REGISTRARS

The transfer agent and registrar for the Common Shares, the Series A Shares and the Series D Shares is CST Trust Company, at its offices in Toronto, Montréal, Vancouver, Calgary, and Halifax.

12. MATERIAL CONTRACTS

Except for certain contracts entered into in the ordinary course of business of APUC and its subsidiaries, the contracts described below are the only contracts entered into by APUC or its subsidiaries during 2014 (or prior to 2014 in the case of contracts that are still in effect) that are material to APUC:

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

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

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

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

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

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

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

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

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

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

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

13. INTERESTS OF EXPERTS

Ernst & Young LLP is the external auditor of the Corporation and have confirmed that they are independent with respect to the Corporation within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulation, and that they are independent accountants with respect to the Corporation under all relevant U.S. professional and regulatory standards.

14. ADDITIONAL INFORMATION

Additional information relating to APUC may be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of APUC's securities and securities authorized for issuance under equity compensation plans is contained in APUC's information circular for its most recent annual meeting. Additional financial information is provided in APUC's financial statements and management discussion and analysis for the year ended December 31, 2014.

SCHEDULE A

Renewable - Hydroelectric, Solar and Wind Facilities

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

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

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

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

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

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

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

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

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

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

[5] APUC currently has hedge agreements in place in respect of each facility. See "Production Method, Principal Markets, Distribution Methods and Material Facilities - Power Generation – Renewable – Wind Power - Material Facilities".

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

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

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

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

SCHEDULE B

Thermal - Biomass, Cogeneration, and Diesel Facilities

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser / 2015 Power Purchase Rates	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of PPA	Lease Expiry Year
Thermal - Biomass Facility						
Facility: Valley Power Facility **Owner**: Valley Power L.P.	12,000	Drayton Valley, Alberta	**Electricity Purchaser:** TransAlta Utilities Corporation **Rates**: Energy: $0.0709/kW-hr	35,000[1]	2014	Owned
Thermal - Cogeneration Facilities						
Facility: Sanger Facility **Owner**: Algonquin Power Sanger LLC (California)	56,000	Sanger, California	**Electricity Purchaser:** PG&E	140,900	2021	Owned
			Rates: US$ 0. 056/ kW-hr (estimated average)* * subject to gas price indexing **Capacity** – Approximately $254,800 January-April &November-December Approximately $935,300 May-October			
Facility: Windsor Locks Facility **Owner**: Algonquin Power Windsor Locks LLC	70,000	Windsor Locks, Connecticut	**Electricity Purchaser:** ISO New England Ahlstrom	27,500 89,000	Merchant 2027	2027
			Rates: ISO New England-Market Rates , included hourly energy, forward capacity and forward reserve payments CT Class III REC ~US$0.2/kW-hr Mill/NGC - US$0.071/kW-hr* Capacity $210,000** Steam - DNM/NGC - US$10.31/1000lbs* Capacity $132,000 * Estimated average rate, includes variable component based on natural gas prices. **Estimated average monthly rate, charges are CPI indexed. Capacity Market and Spot Market – market prices			
Thermal - Diesel Facilities						
Facility: Tinker Thermal Facility **Owner**: Algonquin Tinker Gen Co.	1,000	Perth-Andover, New Brunswick	**Electricity Purchaser:** Not Under Contract **Rates**: Capacity only	0[1]	NA	Owned

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

SCHEDULE C

Wastewater and Water Distribution Facilities

Utility	Owner	Location	Type of Utility	December 31, 2014 Connections[1]	Rates[2]
Black Mountain Sewer System	Liberty utilities (Black Mountain Sewer) Corp.	Carefree, Arizona	Wastewater	2,214	Pursuant to ACC decision 71865
Gold Canyon Sewer System	Liberty Utilities (Gold Canyon Sewer) Corp.	Gold Canyon Arizona	Wastewater	7,515	Pursuant to ACC decision 69664
Bella Vista Water System	Liberty Utilities (Bella Vista Water) Corp.	Sierra Vista, Arizona	Water Distribution	9,357	Pursuant to ACC decision 72251
Tall Timbers Waste System	Liberty Utilities (Tall Timbers Sewer) Corp.	Tyler, Texas	Wastewater	2,277	Pursuant to TCEQ decision 2009-1381-UCR and SOAH decision 582-10-0350
Woodmark Waste System	Liberty Utilities (Woodmark Sewer) Corp.	Tyler, Texas	Wastewater	1,816	Pursuant to TCEQ decision on September 16, 2013
LPSCo Water & Waste System	Liberty Utilities (Litchfield Park Water & Sewer) Corp.	Litchfield, Park, Arizona	Wastewater Water Distribution	21,132 19,007	Pursuant to ACC decision 74437
Fox River Water & Waste System	Liberty Utilities (Fox River Water) LLC	Sheridan, Illinois	Wastewater Water Distribution	219 220	Per customer agreement[3] US $240.08 US $141.61
Timber Creek Water & Waste System	Liberty Utilities (Missouri Water) LLC	DeSoto, Missouri	Wastewater Water Distribution	16 25	Pursuant to MOPSC decision WR-2006-4025
Holiday Hills Water System	Liberty Utilities (Missouri Water) LLC	Branson, Missouri	Water Distribution	485	Per MOPSC Case WR-2006-4025
Ozark Water & Waste System	Liberty Utilities (Missouri Water) LLC	Kimberling City, Missouri	Wastewater Water Distribution	230 255	Pursuant to MOPSC decision WR-2006-4025
Holly Lake Water & Waste System	Liberty Utilities (Silverleaf Water) LLC	Hawkins, Texas	Wastewater Water Distribution	152 1,929	Pursuant to TCEQ decision 2009-2087-UCR & SOAH decision 582-10-2369
Big Eddy Water & Waste System	Liberty Utilities (Silverleaf Water) LLC	Flint, Texas	Wastewater Water Distribution	413 684	Pursuant to TCEQ decision 2009-2087-UCR & SOAH decision 582-10-2369
Piney Shores Water & Waste System	Liberty Utilities (Silverleaf Water) LLC	Conroe, Texas	Wastewater Water Distribution	269 274	Pursuant to TCEQ decision 2009-2087-UCR & SOAH decision 582-10-2369

Utility	Owner	Location	Type of Utility	December 31, 2014 Connections[1]	Rates[2]
Hill Country Water & Waste System	Liberty Utilities (Silverleaf Water) LLC	New Braunfels, Texas	Wastewater Water Distribution	407 225	Pursuant to TCEQ decision 2009-2087-UCR & SOAH decision 582-10-2369
Rio Rico Water & Waste System	Liberty Utilities (Rio Rico Water & Sewer) Corp.	Rio Rico, Arizona	Wastewater Water Distribution	2,215 6,800	Pursuant to ACC decision 73996
Northern Sunrise Water System	Liberty Utilities (Northern Sunrise Water) Corp.	Sierra Vista, Arizona	Water Distribution	363	Pursuant to ACC decision 72251
Southern Sunrise Water System	Liberty Utilities (Southern Sunrise Water) Corp.	Sierra Vista, Arizona	Water Distribution	872	Pursuant to ACC decision 72251
Entrada Del Oro Waste System	Liberty Utilities (Entrada Del Oro Sewer) Corp.	Gold Canyon, Arizona	Wastewater	336	Pursuant to decision 68306
Seaside Resort Water & Waste System	Liberty Utilities (Seaside Water) LLC	Galveston, Texas	Water Distribution Wastewater	156 156	Per customer agreement[2] US $166.68 US $165.45
Noel Water System	Liberty Utilities (Missouri Water) LLC	Noel, Missouri	Water Distribution	697	Pursuant to MOPSC decision WR-2009-0395
KMB Water & Waste System	Liberty Utilities (Missouri Water) LLC	Jefferson, Franklin and Cape Girardeau counties in Missouri	Wastewater Water Distribution	185 550	Pursuant to MOPSC decision WO-2010-0345
Pine Bluff Water System	Liberty Utilities (Pine Bluff Water) Inc.	Pine Bluff, Arkansas	Water Distribution	17,830	Pursuant to APSC decision Docket No. 09-130-U
White Hall Water System	Liberty Utilities (White Hall Water) Corp., and Liberty Utilities (White Hall Sewer) Corp.	White Hall, Arkansas	Wastewater Water Distribution	1,825 1,921	Pursuant to rate agreement with City of White Hall dated May 30, 2014
Total connections				**103,027**	

[1] Inclusive of vacant connections.

[2] See www.libertyutilities.com for complete rate tariffs.

[3] Rates charged per agreement with developer.

SCHEDULE D

Electrical Distribution Facilities

Utility	Owner	Location	Type of Utility	December 31, 2014 Connections[1]	Rates[2]
CalPeco Electric System	Liberty Utilities (CalPeco Electric) LLC	Lake Tahoe, California	Electricity Distribution	Residential – 42,487 Commercial & Industrial – 5,791	Rates pursuant to CPUC decision 12-11-030
Granite State Electric System	Liberty Utilities (Granite State Electric) Corp	Salem, New Hampshire	Electricity Distribution	Residential – 37,981 Commercial & Industrial – 6,660	Rates pursuant to NHPUC decision DE 13-063
Total Connections				**92,900**	

[1] Inclusive of vacant connections.

[2] See www.libertyutilities.com for complete rate tariffs.

SCHEDULE E

Natural Gas Distribution Facilities

Utility	Owner	Location	Type of Utility	December 31, 2014 Connections[1]	Rates[2]
EnergyNorth Gas System	Liberty Utilities (EnergyNorth Natural Gas) Corp.	Manchester, New Hampshire	Natural Gas Distribution	Residential – 82,545 Commercial & Industrial – 9,585	Rates pursuant to NHPUC decision DG 14-180
Peach State Gas System	Liberty Utilities (Peach State Natural Gas) Corp.	Columbus, Gainesville, GA	Natural Gas Distribution	Residential – 53,802 Commercial & Residential – 4,330	Rates pursuant to GPSC Docket #34734 Document #156121
New England Gas System	Liberty Utilities (New England Natural Gas Company) Corp.	Fall River, North Attleboro, Plainville, Westport, Swansea, Somerset, Massachusetts	Natural Gas Distribution	Residential – 52,155 Commercial & Industrial – 3,696	Rates pursuant to M.D.P.U 10-114
Midstates Gas System - Illinois	Liberty Energy (Midstates Natural Gas) Corp.	Salem, Virden, Vandalia, Xenia, Metropolis, Illinois	Natural Gas Distribution	Residential – 21,485 Commercial & Industrial – 2,120	Rates pursuant to ICC decision IL-14-0371
Midstates Gas System - Iowa	Liberty Energy (Midstates Natural Gas) Corp.	Keokuk, Iowa	Natural Gas Distribution	Residential – 4,025 Commercial & Industrial – 461	Rates pursuant to IUB decision TF-01-68
Midstates Gas System - Missouri	Liberty Energy (Midstates Natural Gas) Corp.	Jackson, Sikeston, Butler, Kirksville, Hannibal, Missouri	Natural Gas Distribution	Residential – 51,149 Commercial & Industrial – 6,746	Rates pursuant to MOPSC decision GR-2014-0152
Total Connections				**292,099**	

[1] Inclusive of vacant connections.

[2] See www.libertyutilities.com for complete rate tariffs.

SCHEDULE F

ALGONQUIN POWER & UTILITIES CORP.

MANDATE OF THE AUDIT COMMITTEE

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

1 PURPOSE

1.1 The Committee's purpose is to:

(a) assist the Board's oversight of:

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

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

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

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

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

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

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

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

2 COMMITTEE MEMBERSHIP

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

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

(a) be a director of the Corporation;

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

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

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

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

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

3 COMMITTEE MEETINGS

3.1 Time and Place of Meetings – The time and place of the meetings of the Committee and the calling of meetings and the procedure in all things at such meetings shall be determined by the Committee; provided, however, that the Committee shall meet at least quarterly and meetings of the Committee shall be convened whenever requested by the external auditors or any member of the Committee in accordance with the Canada Business Corporations Act. A majority of the members of the Committee shall constitute a quorum and the Committee shall maintain minutes or other records of its meetings and activities.

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

(a) representatives of Management;

(b) the external auditor; and

(c) the internal audit personnel.

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

4 COMMITTEE AUTHORITY AND RESOURCES

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

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

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

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

5 REMUNERATION OF COMMITTEE MEMBERS

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

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

6 DUTIES AND RESPONSIBILITIES OF THE COMMITTEE

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

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

(a) Financial and Related Information

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

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

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

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

(A) all critical accounting policies and practices to be used, including, without limitation, the reasons why certain estimates or policies are or are not considered critical and how current and anticipated future events impact those determinations and an assessment of

Management's disclosures along with any significant proposed modifications by the auditors that were not included;

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

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

(D) major issues regarding financial statement presentations;

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

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

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

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

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

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

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

(b) External Auditor

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

to the Board and the Committee as representatives of shareholders and that it will report directly to the Committee.

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

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

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

(B) In accordance with applicable laws and regulations, the Committee shall pre-approve any non-audit services (including, without limitation, fees therefor) provided to the Corporation or its subsidiaries by the external auditor or any auditor of any such subsidiary and shall consider whether these services are compatible with the external auditor's independence, including, without limitation, the nature and scope of the specific non-audit services to be performed and whether the audit process would require the external auditor to review any advice rendered by the external auditor in connection with the provision of non-audit services. The Committee may delegate to one or more designated members of the Committee, such designated members not being members of management, the authority to approve additional non-audit services that arise between Committee meetings, provided that such designated members report any such approvals to the Committee at the next scheduled meeting.

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

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

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

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

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

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

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

(vii) Regulatory Matters – The Committee shall discuss with the external auditor the matters required to be discussed by Section 5741 of the CICA Handbook – Assurance relating to the conduct of the audit.

(c) Internal Audit Function – Controls

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

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

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

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

(d) Risk Assessment and Risk Management

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

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

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

(e) Legal Compliance

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

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

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

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

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

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

(h) Review of the Management's Certifications and Reports – The Committee shall review and discuss with Management all certifications of financial information, management reports on internal controls and all other management certifications and reports relating to the Corporation's financial position or operations required to be filed or released under applicable laws and regulations prior to the filing or release of such certifications or reports.

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

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

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

7 REPORTING TO THE BOARD

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

8 EVALUATION OF COMMITTEE PERFORMANCE

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

8.2 Amendments to Mandate

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

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

9 LEGISLATIVE AND REGULATORY CHANGES

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

10 CURRENCY OF MANDATE

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

SCHEDULE G

GLOSSARY OF TERMS

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

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

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

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

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

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

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

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

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

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

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

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

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

"**APCH**" means Algonquin Power (Canada) Holdings Inc. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

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

"**APCo**" means Algonquin Power Co. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

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

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

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

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

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

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

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

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

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

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

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

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

"**Avoided Costs**" means costs a utility does not incur to add new generating capacity to the system by purchasing electricity from an independent or parallel generator. See *"Schedule A - Renewable - Hydroelectric, Solar and Wind Facilities".*

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

"**CPUC**" has the meaning ascribed thereto under *"Description of the Business - Distribution Group - Description of Operations - Water Distribution and Waste water Collection Systems - Principal Markets and Regulatory Environments"*.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

"**Emera**" means Emera Inc.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

"**GW**" means a gigawatt.

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

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

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

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

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

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

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

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

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

"**ISO-NE**" has the meaning ascribed thereto under the heading *"Description of the Business - Generation Group - Description of Operations - Thermal (Cogeneration) Electric Generating Facilities - Principal Markets and Distribution Methods".*

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

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

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

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

"**kV**" means a kilovolt.

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

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

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

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

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

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

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

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

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

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

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

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

"**LU GP1**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**LU GP2**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

"**MW**" means megawatt.

"National Grid" means National Grid USA

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

"**PTAM**" has the meaning ascribed thereto under *"Description of the Business - Distribution Group - Description of Operations - Water Distribution and Waste Water Collection Systems - Principal Markets and Regulatory Environments".*

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

"**PUC Texas**" has the meaning ascribed thereto under *"Description of the Business - Distribution Group - Description of Operations - Water Distribution and Waste Water Collection Systems - Principal Markets and Regulatory Environments".*

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

"**Saint-Damase GP**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Sandy Ridge Wind Facility**" means the Sandy Ridge wind energy facility.

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

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

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

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

"September Offering" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Corporate - Issuance of Common Shares".*

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

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

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

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

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

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

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

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

"Series D Shares" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Corporate".*

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

"**Share Reorganization**" has the meaning ascribed thereto "*Description of Capital Structure - Stock Option Plan*".

"SKIC 20" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**St. Alban Hydro Facility**" means the St. Alban hydroelectric generating facility.

"**Ste. Brigitte Hydro Facility**" means the St. Brigitte hydroelectric generating facility.

"**Steelworkers**" has the meaning ascribed thereto under *"Enterprise Risk Management - Labour Relations".*

"**St. Leon II LP**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**St. Leon II Wind Facility**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**St. Leon GP**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**St. Leon LP**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**St. Leon Trust**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**St. Leon Wind Facility**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Stock Option Plan**" has the meaning ascribed thereto under the heading "*Description of Capital Structure - Stock Option Plan*".

"Strategic Investment Agreement" has the meaning ascribed thereto under the heading *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2012 - Corporate".*

"**Subscription Receipts**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Corporate".*

"**Successor Corporation**" has the meaning ascribed thereto "*Description of Capital Structure - Stock Option Plan*".

"**SWRCB**" has the meaning ascribed thereto under *"Description of the Business - Distribution Group - Description of Operations - Water Distribution and Waste Water Collection Systems - Principal Markets and Regulatory Environments".*

"**Tax Partner**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2013 - Generation Group".*

"**TCE**" has the meaning ascribed thereto under *"Enterprise Risk Management - Operational Risk Management - Specific Environmental Risks - Distribution Group".*

"**TCEQ**" has the meaning ascribed thereto under *"Description of the Business - Distribution Group - Description of Operations - Water Distribution and Waste Water Collection Systems - Principal Markets and Regulatory Environments".*

"**Tennessee**" has the meaning ascribed thereto under *"Description of the Business - Transmission Group - Description of Operations - Natural Gas Pipeline Transmission - Investments".*

"**Tinker Gen Co.**" means Algonquin Tinker Gen Co., a Wisconsin company. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Tinker Hydro Facility**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Hydroelectric Generating Facilities - Material Facilities".*

"**TMC**" has the meaning ascribed thereto under *"Legal Proceedings and Regulatory Actions - Legal Proceedings - Long Sault Global Adjustment Claim"*.

"**TMO**" has the meaning ascribed thereto under *"Risk Factors - Acquisitions and Divestitures"*.

"**Trafalgar**" has the meaning ascribed thereto under "*Description of the Business - Business Associations with APMI and Senior Executives"*.

"**Trafalgar Hydro Facilities**" has the meaning ascribed thereto under *"Legal Proceedings and Regulatory Actions - Legal Proceedings - Trafalgar Proceedings"*.

"**Transmission Group**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Treasury Purchase**" has the meaning ascribed thereto under *"Dividends - Dividend Reinvestment Plan".*

"**TSX**" means the Toronto Stock Exchange.

"**Unit Exchange**" has the meaning ascribed thereto under *"Corporate Structure - Name, Address and Incorporation"*.

"Unit Exchange Transaction" has the meaning ascribed thereto under *"Enterprise Risk Management - Financial Risk Management - Tax Risk and Uncertainty".*

"**USDOE**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Competitive Conditions".*

"**U.S. Wind Portfolio Facilities**" has the meaning ascribed thereto under "*Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**UWUA**" has the meaning ascribed thereto under *"Risk Factors - Labour Relations"*.

"**Val-Eo Partnership**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Valley Power Thermal Facility**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Vestas**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Wind Power Generating Facilities - Material Facilities".*

"**WCI**" has the meaning ascribed thereto under *"Enterprise Risk Management - Operational Risk Management - Specific Environmental Risks - Generation Group".*

"**Windlectric**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**Windsor LLC**" means Algonquin Power Windsor Locks LLC, a Connecticut limited liability company. See *"Description of the Business - Generation Group - Description of Operations - Thermal (Cogeneration) Electric Generating Facilities" - Material Facilities".*

"Windsor Locks Thermal Facility" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Thermal (Cogeneration) Electric Generating Facilities - Material Facilities".*

"**WE HoldCo**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**WP HoldCo**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"WP SponsorCo" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**WPPI**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Wind Power Generating Facilities - Material Facilities".*

*"***WP SponsorCo**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships- Subsidiaries".*