# Table of Contents

1. CORPORATE STRUCTURE  
   1.1 Name, Address and Incorporation 3  
   1.2. Intercorporate Relationships 3  
     1.2.1 Subsidiaries 3  
     1.2.2 Other Interests in Energy Related Developments 8  
2. GENERAL DEVELOPMENT OF THE BUSINESS 9  
   2.1 General 9  
     2.1.1 Business Strategy 9  
   2.2 Three Year History and Significant Acquisitions 10  
     2.2.1 Fiscal 2014 10  
     2.2.2 Fiscal 2015 13  
     2.2.3 Fiscal 2016 14  
   2.3 Recent Developments - 2017 16  
3. DESCRIPTION OF THE BUSINESS 17  
   3.1. Renewable Generation Group 18  
     3.1.1 Regulatory Regimes 18  
     3.1.2 Description of Operations 19  
     3.1.3 Specialized Skill 29  
     3.1.4 Competitive Conditions 29  
     3.1.5 Cycles & Seasonality 29  
     3.1.6 Customers 30  
   3.2 Liberty Utilities Group 30  
     3.2.1 Regulatory Regimes 30  
     3.2.2 Description of Operations 31  
     3.2.3 Specialized Skill 46  
     3.2.4 Competitive Conditions 46  
     3.2.5 Cycles & Seasonality 46  
     3.2.6 Customers 47  
   3.3 Related Party Transactions 48  
   3.4 Principal Revenue 48  
   3.5 Environmental Protection 49  
   3.6 Employees 49  
   3.7 Foreign Operations 49  
   3.8 Economic Dependence 49  
   3.9 Social or Environmental Policies 50  
   3.10 Credit Rating 50  
4. ENTERPRISE RISK FACTORS 51  
   4.1. Treasury Risk Factors 52  
     4.1.1 Downgrade in the Corporation's Credit Rating Risk 52  
     4.1.2 Liquidity Risk 52  
     4.1.3 Tax Risk and Uncertainty 53  
     4.1.4 Credit/Counterparty Risk 53
# Table of Contents (Continued)

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>4.1.5 Foreign Currency Risk</td>
<td>54</td>
</tr>
<tr>
<td>4.1.6 Market Price Risk</td>
<td>54</td>
</tr>
<tr>
<td>4.1.7 Commodity Price Risk</td>
<td>55</td>
</tr>
<tr>
<td>4.1.8 Defined Benefit Pension Plan Risk</td>
<td>57</td>
</tr>
<tr>
<td>4.1.9 Substantial Indebtedness Relating to the Empire Acquisition</td>
<td>57</td>
</tr>
<tr>
<td>4.1.10 Interest Rate Risk</td>
<td>57</td>
</tr>
<tr>
<td>4.2 Operational Risk Factors</td>
<td>58</td>
</tr>
<tr>
<td>4.2.1 Mechanical and Operational Risks</td>
<td>58</td>
</tr>
<tr>
<td>4.2.2 Development and Construction Risk</td>
<td>59</td>
</tr>
<tr>
<td>4.2.3 Cycles and Seasonality Risk</td>
<td>59</td>
</tr>
<tr>
<td>4.2.4 Energy Efficiency Risk</td>
<td>59</td>
</tr>
<tr>
<td>4.2.5 Cyber Security</td>
<td>59</td>
</tr>
<tr>
<td>4.2.6 Environmental Risks</td>
<td>60</td>
</tr>
<tr>
<td>4.2.7 Asset Retirement Obligations</td>
<td>60</td>
</tr>
<tr>
<td>4.2.8 Dependence Upon Key Customers</td>
<td>61</td>
</tr>
<tr>
<td>4.2.9 Personnel and Labour</td>
<td>61</td>
</tr>
<tr>
<td>4.2.10 Obligations to Serve</td>
<td>61</td>
</tr>
<tr>
<td>4.2.11 Litigation risks and other contingencies</td>
<td>61</td>
</tr>
<tr>
<td>4.3 Regulatory Climate and Permitting Risks</td>
<td>61</td>
</tr>
<tr>
<td>4.4 Acquisitions and Divestitures</td>
<td>63</td>
</tr>
<tr>
<td>5. DIVIDENDS</td>
<td>64</td>
</tr>
<tr>
<td>5.1 Dividend Reinvestment Plan</td>
<td>64</td>
</tr>
<tr>
<td>6. DESCRIPTION OF CAPITAL STRUCTURE</td>
<td>65</td>
</tr>
<tr>
<td>6.1 Common Shares</td>
<td>65</td>
</tr>
<tr>
<td>6.2 Private Placements of Subscription Receipts and Common Shares to Emera</td>
<td>65</td>
</tr>
<tr>
<td>6.3 Preferred Shares</td>
<td>65</td>
</tr>
<tr>
<td>6.4 Convertible Debentures</td>
<td>67</td>
</tr>
<tr>
<td>6.4.1 Convertible Unsecured Subordinated Debentures</td>
<td>67</td>
</tr>
<tr>
<td>6.5 Employee Share Purchase Plan</td>
<td>67</td>
</tr>
<tr>
<td>6.6 Directors Deferred Share Units</td>
<td>67</td>
</tr>
<tr>
<td>6.7 Performance Share Units</td>
<td>68</td>
</tr>
<tr>
<td>6.8 Shareholders' Rights Plan</td>
<td>68</td>
</tr>
<tr>
<td>6.9 Stock Option Plan</td>
<td>68</td>
</tr>
<tr>
<td>7. MARKET FOR SECURITIES</td>
<td>71</td>
</tr>
<tr>
<td>7.1 Trading Price and Volume</td>
<td>71</td>
</tr>
<tr>
<td>7.1.1 Common Shares</td>
<td>71</td>
</tr>
<tr>
<td>7.1.2 Preferred Shares</td>
<td>71</td>
</tr>
<tr>
<td>7.2 Prior Sales</td>
<td>72</td>
</tr>
<tr>
<td>7.3 Escrowed Securities and Securities Subject to Contractual Restrictions on Transfer</td>
<td>73</td>
</tr>
<tr>
<td>8. DIRECTORS AND OFFICERS</td>
<td>73</td>
</tr>
<tr>
<td>8.1 Name, Occupation and Security Holdings</td>
<td>73</td>
</tr>
</tbody>
</table>
8.2 Audit Committee
  8.2.1 Audit Committee Charter 77
  8.2.2 Relevant Education and Experience 77
  8.2.3 Pre-Approval Policies and Procedures 77
8.3 Corporate Governance, Risk and Compensation Committees 78
8.4 Bankruptcies 78
8.5 Potential Material Conflicts of Interest 78
9. LEGAL PROCEEDINGS AND REGULATORY ACTIONS 78
  9.1 Legal Proceedings 78
  9.2 Regulatory Actions 79
10. INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS 80
11. TRANSFER AGENTS AND REGISTRARS 80
12. MATERIAL CONTRACTS 80
13. INTERESTS OF EXPERTS 81
14. ADDITIONAL INFORMATION 81

SCHEDULE A - RENEWABLE - HYDROELECTRIC, SOLAR AND WIND FACILITIES A - 1
SCHEDULE B - THERMAL - BIOMASS, COGENERATION, AND DIESEL FACILITIES B - 1
SCHEDULE C - WASTEWATER AND WATER DISTRIBUTION FACILITIES C - 1
SCHEDULE D - ELECTRICAL DISTRIBUTION FACILITIES D - 1
SCHEDULE E - NATURAL GAS DISTRIBUTION FACILITIES E - 1
SCHEDULE F - MANDATE TO THE AUDIT COMMITTEE F - 1
SCHEDULE G - GLOSSARY OF TERMS G - 1

All information contained in this Annual Information Form ("AIF") is presented as at December 31, 2016, unless otherwise specified. In this AIF, all dollar figures are in Canadian dollars, unless otherwise indicated.
Caution Concerning Forward-looking Statements and Forward-looking Information

This AIF may contain statements that, to the extent they are not recitations of historical facts, constitutes "forward-looking statements" or "forward-looking information" within the meaning of applicable securities legislation, including the United States Securities Act of 1933, as amended, the United States Securities Exchange Act of 1934, as amended, and applicable Canadian Securities legislation. All forward-looking information and forward-looking statements are given pursuant to the “safe harbour” provisions of applicable securities legislation. The words “anticipates”, “believes”, “budget”, “could”, “estimates”, “expects”, “forecasts”, “intends”, “may”, “might”, “plans”, “projects”, “schedule”, “should”, “will”, “would” and similar expressions are often intended to identify forward-looking information and forward-looking statements, although not all forward-looking information or forward-looking statements contain these identifying words. The forward-looking information and forward-looking statements reflect management’s current beliefs and are based on information currently available to the Corporation’s management.

Forward-looking information and forward-looking statements are included throughout this AIF, 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 and forward-looking information relate to future events and conditions, by their very nature they require making assumptions and involve inherent risks and uncertainties. The Corporation (as defined in this AIF) cautions that although it believes 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 and forward-looking information. The forward-looking information and forward-looking statements are subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by such information or statements. Factors which could cause results or events to differ from current expectations include, but are not limited to: derivative financial instruments, including, but not limited to, hedging availability; commodity price and availability risk; foreign exchange risk; interest rate risk; commercial relationship risk; credit risk; labour risk; weather risk; regulatory risk; environmental risk; capital market risk, including, but not limited to, economic conditions, cost of financing, capital resources and liquidity risk; construction and development risks; the anticipated benefits of the acquisitions, including the Empire Acquisition (as defined in this AIF) may not materialize or may not occur within the time periods anticipated by the Corporation; impact of significant demands placed on the Corporation as a result of acquisitions; failure to repay the non-revolving credit facilities in favor of Algonquin in an aggregate amount of US$0.9 billion (the “Empire Acquisition Credit Facilities”); increased indebtedness of Algonquin after the closing of the Empire Acquisition; the Empire Acquisition and related financing, including the Debenture Offering (as defined in this AIF), could result in a downgrade of credit ratings of the Corporation, the Empire District Electric Company (“Empire”) and/or their subsidiaries; historical and pro forma combined financial information may not be representative of future performance; potential undisclosed liabilities of Empire and its subsidiaries; ability to retain key personnel of an acquired company following its acquisition; operating and maintenance risks; risks associated with changes in economic conditions; developments in technology could reduce demand for electricity, gas and water; changes in customer energy usage patterns; risk of failure of information technology infrastructure and cybersecurity; disruption of fuel supply; natural disasters or other catastrophic events; impairment testing of certain long-lived assets could result in impairment charges; risks relating to the Debentures and the Common Shares (each as defined in this AIF); unanticipated maintenance and other expenditures; risk associated with the continuation, renewal, replacement and/or regulatory approval of power supply and capacity purchase contracts; risks associated with pension plan performance and funding requirements; regulatory and government decisions including, but not limited to, changes to environmental, financial reporting and tax legislation and regulations; risk of loss of licences and permits; risk of loss of service area; market energy sales prices; changes to the regulation of rates that subsidiaries of the Corporation charge their utility customers; risk of condemnation; and adverse publicity and reputational risk.

Material risk factors include those set out in this AIF under “Enterprise 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 forward-looking information. Given these risks, undue reliance should not be placed on these forward-looking statements or forward-looking information. In addition, such statements and information are made based on information available and expectations as of the date of this AIF and such expectations may change after this date. APUC is not obligated to nor does it intend to update or revise any forward-looking statements or forward-looking information, whether as a result of new information, future developments or otherwise, except as required by law.
Non-GAAP Financial Measures

The terms “Adjusted Net Earnings”, “Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization” (“Adjusted EBITDA”), “Adjusted Funds from Operations”, "Net Energy Sales", "Net Utility Sales" and "Divisional Operating Profit" are used throughout this AIF. These terms are not recognized measures under GAAP. There is no standardized measure of “Adjusted Net Earnings”, 'Adjusted EBITDA", "Adjusted Funds from Operations", "Net Energy Sales", "Net Utility Sales", and "Divisional Operating Profit"; and 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", "Net Energy Sales", "Net Utility Sales", and "Divisional Operating Profit" can be found in APUC’s most recent management’s discussion and analysis (“MD&A”) for the year ended December 31, 2016, which calculation and analysis is incorporated herein by reference.

Use of Non-GAAP Financial Measures

Adjusted EBITDA

EBITDA is a non-GAAP measure used by many investors to compare companies on the basis of their 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 Corporation. Where APUC manages the day to day operations of a facility and receives the majority of its economic benefits, the full operating profit of such facility is included in calculating the measure. APUC believes that presentation of this measure will enhance an investor’s understanding of APUC’s operating performance. Adjusted EBITDA is not intended to be representative of cash provided by operating activities or results of operations determined in accordance with GAAP.

Adjusted net earnings

Adjusted Net Earnings is a non-GAAP 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 that are viewed as not directly related to a company’s operating performance. 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, which can be impacted positively or negatively by these items.

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 that are viewed as not directly related to a company’s operating performance. 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 by 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. Where APUC manages the day to day operations of a facility and receives the majority of its economic benefits, the Adjusted Funds from Operations of the entire facility is included in calculating the measure. 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, which can be impacted positively or negatively by these items.
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 such revenue generally increases or decreases in response to increases or decreases in the cost of the commodity used 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 rates that are charged to customers. 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 commodity costs 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 utility customers. 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.

Divisional Operating Profit

Divisional Operating Profit is a non-GAAP measure. APUC uses Divisional Operating Profit to assess the operating performance of its business groups without the effects of (as applicable): depreciation and amortization expense, corporate administrative expenses, 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, 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 divisional units. Divisional Operating Profit is calculated inclusive of Hypothetical Liquidation at Book Value income, which represents the value of net tax attributes earned in the period from electricity generated by certain of its U.S. wind power and U.S. solar generation facilities. Where the Corporation manages the day to day operations of a facility and receives the majority of its economic benefits, the full operating profit of such facility is included in calculating the measure. APUC believes that presentation of this measure will enhance an investor's understanding of APUC's divisional operating performance. Divisional Operating Profit is not intended to be representative of cash provided by operating activities or results of operations determined in accordance with GAAP.
1. CORPORATE STRUCTURE

1.1 Name, Address and Incorporation

Algonquin Power & Utilities Corp. ("APUC" or the "Corporation") was originally incorporated under the Canada Business Corporations Act 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 amendment 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. ("APCo") (the "Unit Exchange Transaction") and changed its name to Algonquin Power & Utilities Corp. ("APUC"). 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 "Corporation" 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 "Corporation" 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 Intercompany Relationships

1.2.1 Subsidiaries

The subsidiaries of APUC are grouped by two primary North American business units of the Corporation consisting of the Renewable Generation Group, and the Liberty Utilities Group. The principal holding for APUC’s Renewable Generation Group is an investment in 100% of the issued and outstanding trust units of APCo. The principal holding for the Corporation’s Liberty Utilities Group is an investment in 100% of the issued and outstanding common shares of Liberty Utilities (Canada) Corp. ("LU Canada"), a Canadian 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 membership interests in Liberty Utilities (America) Holdings LLC, a Delaware LLC, 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 U.S. based transmission subsidiaries, principally Liberty Utilities (Pipeline & Transmission) Corp., a Delaware corporation. The Canadian transmission assets are held by Algonquin Power (Ontario Transmission) Inc., which is 100% owned by LU Canada. The ownership chains for both of these primary business operations of the Corporation are described below.

In regard to the Renewable Generation Group, the subsidiaries of APCo include the ownership chains of Algonquin Power Trust ("APT") and Algonquin Power (Canada) Holdings Inc. ("APCH"). APCo directly owns a 100% interest in Windlectric Inc. ("Windlectric"), a Canadian federal corporation that is developing a wind project in Ontario, and APCo owns 100% of the issued and outstanding shares of Cornwall Solar Inc. ("Cornwall Solar", which owns a solar power facility in Cornwall, Ontario (the "Cornwall Solar Facility"). 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 Liberty Utilities Group, Liberty Utilities has direct and indirect investments in entities owning electric distribution, natural gas distribution, and water distribution utility systems in California, Iowa, Illinois, Kansas, Missouri, Montana, Oklahoma, Arkansas, Georgia, Massachusetts and New Hampshire. Through its subsidiary, Liberty Utilities Sub Corp. ("Liberty SubCo"), Liberty Utilities has investments in entities that own water distribution and wastewater collection utility systems in Arizona, Illinois, Missouri, and Texas. In addition, Liberty Utilities (Pipeline & Transmission) Corp. and Algonquin Power (Ontario Transmission) Inc. are undertaking the development of transmission projects in the United States and Canada, respectively.

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) Renewable Generation Group

Renewable Generation Group Chain Entities

APCo is the sole beneficiary of APT, which owns all of the trust certificates of APOT. 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 2496838 Ontario Inc., an indirect subsidiary of APOT, and all of the Class C common shares of APCH are owned by St. Leon Wind Energy GP Inc. ("St. Leon GP"), another indirect APOT subsidiary. APCo also owns 100% of the issued and outstanding shares of Cornwall Solar, which owns the Cornwall Solar Project in Cornwall, Ontario and APCo directly owns a 50% ownership in Windlectric, a Canadian federal corporation that is developing a wind project in Ontario. APCo is also the sole owner of eleven Ontario numbered companies which hold various rights to a pipeline of pending solar projects in Ontario.

APT Group

APT forms part of the Renewable Generation Group. 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. APT directly owns a 2% limited partnership interest in the Algonquin Power (Mont-Laurier) Limited Partnership (the "Mont-Laurier Partnership"), a Québec limited partnership, which owns the Mont-Laurier hydroelectric facility (the "Mont-Laurier Hydro Facility") and the Côte Ste.-Catherine hydroelectric generating facility (the "Côtes Ste.-Catherine Hydro Facility"), while APCO owns the remaining 98% partnership interests, comprised of an 86.5% limited partnership interest and an 11.5% general partnership interest.

APT directly owns the Hydraska hydroelectric generating facility (the "Hydraska Hydro Facility") and the Arthurville hydroelectrical generating facility (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, société en commandite ("Val-Éo Partnership") which owns the 125 MW project located in the local municipality of Saint-Gideon de Grandmont (the "Val-Éo Wind Project"). A non-APUC related entity, Val-Éo Coop de solidarité, owns 74.995% of the Val-Éo Partnership. The remaining 0.01% interest in the Val-Éo Partnership is owned by a Quebec company, Éoliennes Belle-Rivières Inc., the general partner. The interests in Éoliennes Belle-Rivières Inc. are owned 75% by Val-Éo 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 facility (the "Saint-Damase Wind Facility"). The remaining 50% is owned by Corporation Municipal de Saint-Damase, a non-APUC related entity, which also owns 100% of the preferred shares issued by Saint-Damase GP.

In 2016, APT acquired a 75% interest in Red Lily Wind Energy Partnership ("Red Lily Partnership"), a Saskatchewan general partnership which owns a 25 MW wind facility near Moosomin, Saskatchewan. The remaining 25% interest in Red Lily Partnership is owned by two non-APUC related entities: C.C. Acquisition Corp. and Red Lily Wind Energy Corp.
APOT Group

APOT is an unincorporated open ended trust created by a trust indenture effective January 2, 1997, in accordance with the laws of the Province of Alberta. APOT is governed by a Second Amended and Restated Trust Indenture, effective December 8, 2014.

APOT controls the entities that own the 104 MW wind facility located at St. Leon, Manitoba (the “St. Leon Wind Facility”). The St. Leon Wind Facility is owned by St. Leon Wind Energy LP, a Manitoba limited partnership (“St. Leon LP”). St. Leon LP is owned by its general partner, 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 (“Series C Share”). St. Leon Trust and St. Leon GP are 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, Algonquin (AirSource) GP Inc., an Ontario corporation which holds the remaining 0.01% general partnership interest. 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 also owns 100% of 2496838 Ontario Inc., an Ontario corporation.

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 in Valley Power LP, an Alberta limited partnership which owns the Alberta biomass 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 Hurdman hydroelectrical generating facility (the “Hurdman Hydro Facility”). In Québec, APCH directly owns the hydro facilities known as Hydro Snemo, St. Raphael, Belletre, and St. Brigette, in addition to owning 100% of the beneficial interests in the Rawdon and St. Alban hydroelectrical facilities (the "Rawdon Hydro Facility" and "St. Alban Hydro Facility" respectively). APCH also holds a direct interest in Société Hydro-Donnacona, S.E.N.C. (“Donnacona LP”), the owner of the Donnacona hydroelectrical facility (the "Donnacona Hydro Facility"). Donnacona LP 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 APCH. APCH also owns a 99.99% interest in Société en Commandité Chute Ford, a Quebec limited partnership which owns the Glenford hydroelectric facility and APCH owns 100% of Glenford Minority Inc., an Ontario Corporation, which is the general partner, holding a 0.01% interest in Société en Commandité Chute Ford.

APCH owns a 99% interest in Algonquin Power (Morse) LP, an Ontario limited partnership, which owns the Morse Wind Facility in Saskatchewan (the "Morse Wind Facility"). 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.

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 Rapids hydroelectric facility (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 Hydro Facility. APCI is also the sole owner of Algonquin Power (Long Sault) Corporation Inc., an Ontario corporation which is the other general partner, holding the remaining 0.1% general partnership interest, in the LS Partnership.

APCH also holds note receivables in Long Sault Hydro Facility, which effectively provides it with the right to 100% of the after tax cash flows of the facility up to the end of 2013, 65% from 2014 to 2027 and 58% thereafter.
APCH has formed two Canadian federal corporations, Blue Hills Wind Managing Partner Inc. and Blue Hills Wind Minority Partner Inc., which collectively own a Saskatchewan general partnership: Blue Hills Wind Energy Project Partnership. This partnership was set up to take ownership of the Saskatchewan wind project that was owned by Windlectric.

APCH also owns 100% of Algonquin Power Services Canada Inc., a Canadian federal corporation that provides purchasing services to the Corporation's Canadian entities.

**APFA Group**

APFA, a Delaware corporation, is owned by Algonquin Power (America) Inc ("APA"), a Delaware corporation which owns 100% of APFA's common shares and by APA's parent APCH which owns 100% of APFA's Series A Preferred shares. APFA owns or holds interests in the thermoelectric, solar and wind entities and facilities in the U.S.

APFA owns Algonquin Power Sanger LLC, ("Sanger LLC") a California limited liability company, and Algonquin Power Windsor Locks LLC ("Windsor LLC"), a Connecticut limited liability company. These entities respectively own the U.S. Sanger facility and the Windsor Locks Thermal facility. APFA also owns KMS Crossroads, LLC, a Delaware limited liability corporation.

APFA owns Algonquin Tinker Gen Co. ("Tinker Gen Co.") and Algonquin Northern Maine Gen Co. ("Northern Maine Gen Co.") and Algonquin Great Bay Solar Holdings, LLC, a Delaware LLC, which holds the real estate and obligations of Great Bay Solar Project in Somerset County, Maryland. $APFA$ also owns Algonquin Power (Bakersfield Land Holdings) LLC, a Delaware LLC which holds the real property leased to SKIC 10 and SKIC 20.

APFA owns 100% of Algonquin Power Services Canada Inc., a Canadian federal corporation that provides purchasing services to the Corporation's Canadian entities.

**APFA group**

APFA, a Delaware corporation, is owned by Algonquin Power (America) Inc ("APA"), a Delaware corporation which owns 100% of APFA's common shares and by APA's parent APCH which owns 100% of APFA's Series A Preferred shares. APFA owns or holds interests in the thermoelectric, solar, and wind entities and facilities in the U.S.

APFA owns Algonquin Power Sanger LLC, ("Sanger LLC") a California limited liability company, and Algonquin Power Windsor Locks LLC ("Windsor LLC"), a Connecticut limited liability company. These entities respectively own the U.S. Sanger facility and the Windsor Locks Thermal facility. APFA also owns KMS Crossroads, LLC, a Delaware limited liability corporation.

APFA owns Algonquin Tinker Gen Co. ("Tinker Gen Co.") and Algonquin Northern Maine Gen Co. ("Northern Maine Gen Co.") and Algonquin Great Bay Solar Holdings, LLC, a Delaware LLC, which holds the real estate and obligations of Great Bay Solar Project in Somerset County, Maryland. $APFA$ also owns Algonquin Power (Bakersfield Land Holdings) LLC, a Delaware LLC which holds the real property leased to SKIC 10 and SKIC 20.

APFA owns 100% of the interests in Algonquin Power (Gearbox Holdings), LLC, a Delaware LLC, which 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. ("APFA Holdco"), a Delaware corporation which is 100% owned by APFA. WP SponsorCo owns 100% of the Class B managing interests in Wind Portfolio Holdings, LLC (“WP HoldCo”), a Delaware LLC. Non-Algonquin partners, JPM Capital Corporation, Morgan Stanley Wind LLC, and Gear Wind LLC, collectively hold 100% of the non-managing Class A interest in WP HoldCo, which in turn owns Wind Energy Portfolio Holdings I, LLC (“WE HoldCo”), a Delaware LLC. WE HoldCo directly owns three entities which each own separate wind projects in the USA: Sandy Ridge Wind, LLC, a Delaware LLC, owns the Sandy Ridge wind energy facility (the "Sandy Ridge Wind Facility" in Pennsylvania; Minonk Wind, LLC, a Delaware LLC, owns the Minonk wind energy facility (the "Minonk Wind Facility") in Illinois and Senate Wind, LLC, a Delaware LLC, owns the Senate wind energy facility (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 (the "Shady Oaks Wind Facility") in Illinois.

APFA owns Algonquin Power (Odell Holdings) Inc., a Delaware corporation, which owns Odell SponsorCo, LLC (“Odell SponsorCo”), a Delaware LLC. Odell SponsorCo owns 100% of the Class B managing interests in Odell Holdings, LLC, a Delaware LLC. Third party partners, not affiliated with the Corporation, collectively hold 100% of the non-managing Class A (tax equity) interests in Odell Holdings, LLC. Odell Holdings, LLC owns Odell Wind Farm, LLC, a Minnesota LLC, which owns the Odell wind facility (the "Odell Wind Facility") near Windom, Minnesota.

APFA owns Algonquin Power (Deerfield Holdings) Inc., a Delaware corporation which owns a 50% the membership interest in Deerfield Wind SponsorCo, LLC (“Deerfield SponsorCo”), a Delaware LLC. The remaining 50% of Deerfield SponsorCo is owned by Deerfield Holdings I, LLC, a subsidiary of Renewable Energy Systems Americas Inc., a third party unaffiliated with the Corporation. Deerfield SponsorCo owns Deerfield Holdco, LLC, a Delaware LLC, which owns Deerfield Wind Energy, LLC, a Delaware LLC which owns Deerfield wind facility (the “Deerfield Wind Facility”) in Michigan.

APFA owns GB Solar Holdings, LLC, a Delaware LLC, which owns Great Bay Solar I, LLC, a Maryland LLC. Great Bay Solar I, LLC owns and is developing a solar facility (the "Great Bay Solar Project") in Somerset County, Maryland.

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 (the "Bakersfield I Solar Facility") in California. A non-affiliated third party partner owns the Class A (tax equity) non-managing interests in SKIC 20.

APFA owns 100% of Algonquin SKIC 10 SponsorCo, LLC ("SKIC 10 SponsorCo"), a Delaware LLC. SKIC 10 SponsorCo owns 100% of the Class B managing interests in Algonquin SKIC 10 Holdings, LLC, ("SKIC 10 Holdings") a Delaware LLC. A non-affiliated third party partner owns the Class A (tax equity) non-managing interests in SKIC 10 Holdings. SKIC 10 Holdings owns 100% of Algonquin SKIC 10 Solar, LLC ("SKIC 10"), a Delaware LLC, which owns a 10 MW solar facility (the "Bakersfield II Solar Facility") adjacent to the Bakersfield I Solar Facility.

APFA is also the sole owner of Algonquin Power (Bakersfield Land Holdings) LLC, a Delaware LLC which holds the real property leased to SKIC 10 and SKIC 20.
APFA owns a 99% interest in Algonquin Power (Wind Developments) LLC, a Delaware limited liability company set up for future wind development purposes. APFA’s wholly owned subsidiary, APFA Holdco owns the remaining 1% of the LLC.

APFA is also the sole owner of Algonquin Power Services America LLC, a Delaware LLC that provides purchasing services to APCo entities operating in the U.S.

(ii) Liberty Utilities Group

Liberty Utilities 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”).

CalPeco owns 100% of the Class B managing interests in Liberty Utilities (Luning Holdings) LLC (“Luning Holdings”), a Delaware LLC. The Class A non-managing interests in Luning Holdings are owned by Firstar Development, LLC, a non-APUC related entity. Luning Holdings owns 100% of Luning Energy LLC, a Delaware LLC which owns a 50 MW photovoltaic project in Nevada.

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 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”).

Liberty Utilities owns Liberty Utilities (New England Natural Gas Company) Corp., a Delaware corporation registered to do business in Massachusetts, which owns natural gas distribution utility assets in Massachusetts (the “New England Gas System”).


Liberty Utilities owns Western Water Holdings, LLC, a Delaware LLC, which owns Liberty Utilities (Park Water) Corp. (“Park Water”), which owns the Park Water System in Downey, California. Park Water also owns Mountain Water Company (“Mountain Water”), a Montana company which owns the Mountain Water Facility in Missoula, Montana, and Liberty Utilities (Apple Valley Ranchos Water) Corp. (“Apple Valley”), a California company which owns the Apple Valley Ranchos water facility (the “Apple Valley Ranchos Water System”) in Apple Valley, California. These assets were acquired on January 11, 2016.

Liberty Utilities owns 100% of Liberty Utilities (Central) Co., a Delaware corporation, which owns 100% of The Empire District Electric Company (“Empire”), a Kansas corporation. Empire directly owns electric and water distribution utility assets serving locations in Missouri, Kansas, Oklahoma, and Arkansas. It also directly owns the Ozark Beach Hydro facility in Missouri, the Riverton, Energy Center, and Stateline No. 1 natural gas-fired power generation facilities in Kansas and Missouri, the Asbury coal-fired power generation facility in Missouri and a 40% interest in the Stateline combined cycle gas facility in Missouri. Empire owns a 12% interest in the latan coal-fired power generation facility in Missouri, and a 7.5% interest in the Plum Point coal-fired power generation facility in Arkansas. Empire has a direct interest in PPAs for the Elk River and Cloud County wind facilities in Kansas. Empire also owns the Empire District Gas Company, which operates a natural gas distribution utility in locations in Missouri, and Empire District Industries, Inc. which owns a fiber optics business in Missouri. Empire also owns EDE Company Arkansas, LLC, an Arkansas LLC and EDE Property Transfer Corp., a Delaware corporation; both of which are currently inactive and have been set up for potential future activities.

Liberty Utilities also owns Liberty Utilities (Pine Bluff Water) Inc., which owns and operates the Pine Bluff water system (‘Pine Bluff Water System’), located in Pine Bluff, Arkansas.

Liberty Utilities owns Liberty Utilities (White Hall Water) Corp. and Liberty Utilities (White Hall Sewer) Corp., both being Arkansas corporations, which respectively own the White Hall Water System and the White Hall Waste System in Arkansas.

Liberty Utilities also owns Liberty Utilities (Woodson-Hensley Water) Corp., an Arkansas corporation which owns and operates a water storage and distribution system to serve the communities of Woodson and Hensley in Arkansas.
Liberty Utilities owns Liberty Utilities (Pipeline & Transmission) Corp., which owns 50% of Northeast Energy Center, LLC, a Delaware corporation, which is developing a liquefied natural gas facility in Massachusetts. The remaining 50% is owned by RBS Energy, LLC, a non-APUC related entity.

**Liberty Utilities (Sub) Corp.**

Liberty Utilities owns Liberty Utilities (Sub) Corp. ("Liberty SubCo"), a Delaware corporation. With the exception of Pine Bluff Water, Mountain Water, Apple Valley Ranchos Water System, the Park Water System, the White Hall Water and Waste System and the water distribution assets of Empire, Liberty SubCo is the parent company of the water and wastewater entities.

Liberty SubCo owns, through subsidiaries, the water and wastewater businesses located in Arizona, Texas, Missouri and Illinois. Most of these 100% wholly-owned subsidiaries (except Liberty Utilities (Northwest Sewer) Corp.), 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, the Northern Sunrise Water System, and the Southern Sunrise 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 (Rio Rico Water & Sewer) Corp. owns the Rio Rico Water & Waste Systems; and Liberty Utilities (Entrada Del Oro Sewer) Corp. owns the Entrada Del Oro 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.

**LU Canada**

LU Canada owns Algonquin Power (Ontario Transmission) Inc., an Ontario corporation, which owns 50% of Sagatay Holdings Partnership, an Ontario general partnership. The remaining 50% is owned by Morgan Geare Inc., a non-APUC related entity. Sagatay Holdings Partnership owns 49.99% of Sagatay Transmission Limited Partnership, (“Sagatay LP”) an Ontario limited partnership. Sagatay LP is also owned 25% by the Mishkeegogamang First Nation and 25% by the Ojibway Nation of Saugeen First Nation, both of which are non-Algonquin entities. LU Canada also owns Liberty Utilities (Sagatay Transmission) GP Inc., an Ontario corporation, which owns the remaining 0.01% of Sagatay LP and acts as its general partner.

(iii) Other

Outside of APCo, LU Canada and their respective subsidiary entities, as described above, APUC directly owns Warwick (Canada) Corp., an Ontario corporation and 3793257 Canada Inc. ("3793257"), a holding company incorporated under the Canada Business Corporation Act.

APUC also has ownership interests in a group of special purpose financing entities, 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 of 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 controls a limited partnership formed for purposes of holding the corporate head 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 certain notes receivable and non-controlling equity interests 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. It also owns a 33.9% interest in the Class B non-voting preferred shares of Chapais Energie, Société en Commandite.
In addition, APCo is entitled to a royalty in the form of cash flows generated by the Long Sault Hydro Facility. It is also the owner of a 14.14% secured, subordinated 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. APUC also owns the Class B limited partnership units of St. Leon 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 real per share growth in earnings and cash flow to support a growing dividend and share price appreciation.

APUC’s current quarterly dividend to shareholders is U.S. $0.1165 per common share or U.S. $0.4659 per common share per annum. Based on exchange rates as at March 1, 2017, the quarterly dividend is equivalent to Cdn $0.1554 per common share or Cdn $0.6216 per common 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. 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 two primary North American business units consisting of: the Renewable Generation Group which owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation utility assets; and, the Liberty Utilities Group which owns and operates a portfolio of regulated electric, natural gas, water distribution and wastewater collection utility systems, and transmission operations.

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

The Renewable Generation Group owns or has interests in hydroelectric, wind, solar, and thermal facilities with a combined generating capacity of approximately 120 MW, 1,050 MW, 40 MW, and 335 MW, respectively. Approximately 88% of the electrical output from the hydroelectric, wind, and solar generating facilities is sold pursuant to long term contractual arrangements which have a production-weighted average remaining contract life of 16 years.

The Renewable Generation Group also has a portfolio of development projects that when constructed will add approximately 351 MW of generation capacity from wind and solar powered generating facilities that have a production-weighted average contract life of 22 years.

Liberty Utilities Group
The Liberty Utilities Group operates diversified regulated electricity, natural gas, water distribution and wastewater collection utility services. The Liberty Utilities 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 Liberty Utilities Group delivers continued growth in earnings through accretive acquisition of additional utility systems.

On January 1, 2017, Liberty Utilities Co., APUC’s wholly-owned regulated utility business, completed the acquisition of Empire (the “Empire Acquisition”). Empire is a vertically-integrated utility providing electric, natural gas and water service to approximately 218,000 customers in Missouri, Kansas, Oklahoma, and Arkansas.

Including Empire, the Liberty Utilities Group now serves approximately 783,000 customers.

The Liberty Utilities Group’s regulated electrical distribution utility systems and related generation assets are located in the States of California and New Hampshire. With the addition of Empire, the service territory has expanded into Missouri, Kansas, Oklahoma and Arkansas. The Liberty Utilities Group now serves approximately 264,000 electric connections.
The Liberty Utilities Group's regulated natural gas distribution utility systems are located in the States of Georgia, Illinois, Iowa, Massachusetts, New Hampshire and Missouri. With the expanded Missouri service area, the Liberty Utilities Group now serves approximately 336,000 natural gas connections.

The Liberty Utilities Group's regulated water distribution and wastewater collection utility systems are located in the States of Arizona, Arkansas, California, Illinois, Missouri, Montana, and Texas; together serving approximately 183,000 connections.

With the integration of Empire, the Liberty Utilities Group now operates a fleet of regulated generation assets with a net capacity of 1,374MW.

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 2014

Corporate

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

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 were approximately 80% based in the U.S. and generated 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 2014 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 2014 Offering and an additional 2,529,000 Common Shares were issued on the same terms and conditions of the September 2014 Offering. As a result, APUC issued an aggregate of 19,389,000 Common Shares under the September 2014 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 Inc. ("Emera") entered into a subscription agreement pursuant to which Emera agreed to subscribe for an aggregate of 7,866,170 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 their over-allotment option with respect to the September 2014 Offering, 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 were intended to be used to partially finance the acquisitions of the Odell Wind Project and Park Water System.
Renewable Generation Group

(i) Acquisition of Odell Wind Project

On November 14, 2014, the Renewable Generation Group acquired an interest in a 200 MW wind development located in Cottonwood, Jackson, Martin, and Watonwan counties in Minnesota (the “Odell Wind Project”). The Odell Wind Project is situated on approximately 23,000 acres of leased land and utilizes 100 Vestas V110-2.0 wind turbines. Pursuant to a 20-year power purchase agreement (“PPA”), all energy, capacity and Renewable Energy Credits (“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 of the project began in the second quarter of 2015, and construction financing including a portion that bridges to tax equity's investments was arranged by the project company during 2015.

The Renewable Generation Group's participation in the project during the construction phase was structured as a 50% equity interest in a new joint venture with a third party developer. On July 29, 2016, the Odell Wind Facility achieved commercial operation ("COD"). On September 15, 2016, the Corporation acquired the remaining 50% interest in Odell SponsorCo LLC for U.S. $26.5 million and now controls the project.

(ii) Completion of Cornwall Solar Project

During the quarter ended March 31, 2014, the Renewable Generation Group completed the construction of its 10 MW solar project located near Cornwall, Ontario. The facility reached commercial operation on March 27, 2014. The facility represents the first solar project in the Renewable 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 feed in tariff (“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 (the “Saint-Damase Wind Project”) 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-Québec Distribution ("Hydro-Québec").

The turbines and other components utilized in the first 24 MW phase of the Saint-Damase Wind Project qualify as Canadian Renewable and Conservation Expense, and therefore a significant portion of the Phase I capital cost was eligible for a refundable Quebec tax credit with a value of $14.3 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 intended to proceed with the 10 MW Bakersfield II Solar Project on 64 acres of land adjacent to its 20MW Bakersfield I Solar Project in Kern County, California.

The 10MW Bakersfield II Solar Project executed a 20 year PPA on September 22, 2014 with a large California based electric utility.

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

On March 31, 2014, the Renewable 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 wind portfolio in the United States (the “U.S. Wind Portfolio”) for total consideration of approximately U.S. $115.0 million. As a result of the transaction, the Renewable 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 Renewable Generation Group early in 2014 as discussed below.

(vi) $200 million Senior Unsecured Debentures

On January 17, 2014, the Renewable Generation Group issued $200.0 million 4.65% senior unsecured debentures with a maturity date of February 15, 2022 (the “2014 Renewable Generation Group Debentures”) pursuant to a private placement in Canada and the United States. The 2014 Renewable 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 Renewable 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 Renewable Generation Group increased the credit available under the Renewable Generation Group credit facility to $350.0 million from $200.0 million to provide additional liquidity in support of the group's development portfolio. In addition to the larger size, the maturity of the facility was extended from three to four years and now extends until July 31, 2018.

Liberty Utilities Group

(i) Agreement to acquire Park Water

On September 19, 2014, the Liberty Utilities 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, now known as Liberty Utilities (Park Water) Corp. (“Park Water”). The Park Water acquisition closed on January 8, 2016. Please see "2.2.3 Fiscal 2016 Liberty Utilities Group Highlights" for additional description of the Park Water acquisition.

(ii) Acquisition of White Hall Water System

On May 30, 2014, the Liberty Utilities Group acquired the assets of the White Hall water and waste system (the "White Hall Water System" and "White Hall Waste System", respectively) and together the "White Hall Water and Waste System"), a regulated water distribution and wastewater treatment utility located in White Hall, Arkansas. The White Hall Water and Waste System serves approximately 1,900 water distribution and 1,900 wastewater treatment customers. Total purchase price for the White Hall Water System assets, adjusted for certain working capital and other closing adjustments, was 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 NHPUC 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 Georgia Rate Adjustment Mechanism ("GRAM") filing with the Georgia Public Service Commission ("GPSC"). In January 2014, the Liberty Utilities 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). GPSC approval was received on December 4, 2014.

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

On February 28, 2013, the LPSCo Water distribution and wastewater treatment facility (the "LPSCo System") filed a general rate case with the Arizona Corporation Commission ("ACC") related to the LPSCo 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 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 infrastructure system replacement surcharge ("ISRS"). 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 by the MSPC 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. On March 12, 2015, the Pine Bluff Water System received a final order from the Arkansas Public Service Commission approving a revenue increase of U.S. $1.1 million effective March 15, 2015.

(viii) EnergyNorth Gas System Rate Case Proceedings

On August 1, 2014, the EnergyNorth Gas System in New Hampshire filed an application for an increase in revenue of U.S. $16.1 million, or approximately 9.6%. 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. On June 26, 2015, the EnergyNorth Gas System received a final order from the NHPUC approving a settlement agreement allowing for a U.S. $12.4 million revenue increase effective July 1, 2015.

2.2.2 Fiscal 2015

Corporate

(i) Dividend Increased in second quarter 2015 to U.S. $0.385 Per Common Share Annually

On May 7, 2015, the Board approved a dividend increase of U.S. $0.035 annually bringing the total annual dividend to U.S. $0.385 per common share, paid quarterly at the rate of U.S. $0.0963 per common share, an increase of 10% over the previous dividend rate.

(ii) $150 Million Bought Deal Offering of Common Shares

On December 2, 2015 APUC issued on a bought deal basis (the "December 2015 Offering") 14,355,000 Common Shares at a price of $10.45 per share for gross proceeds of approximately $150.0 million.

Net proceeds of the December 2015 Offering were used to partially fund APUC's capital growth program, to reduce short-term debt and for general corporate purposes.

Renewable Generation Group

(i) Deerfield Wind Project Joint Venture

On October 19, 2015, the Renewable Generation Group announced it had agreed to jointly develop the 150 MW Deerfield Wind Project in the United States with RES.

The Deerfield Wind Project is located in central Michigan and is situated on approximately 20,000 acres of leased land. The project utilizes 44 Vestas V110-2.0 wind turbines and 28 Vestas V110-2.2 turbines and is estimated to generate 555.2 GW-hrs annually. The project has a 20 year PPA with a local electric distribution utility serving approximately 260,000 customers in Michigan.

The total project cost is expected to be approximately U.S. $303.0 million. The project achieved commercial operations on February 21, 2017.

(ii) Great Bay Solar Project

On December 1, 2015, the Renewable Generation Group announced the development of a new 75 MW contracted solar generation facility, located in Somerset County Maryland ("Great Bay Solar Project"). The U.S. $180.0 million facility is expected to achieve commercial operations expected by the end of 2017. The facility is contracted under a 10 year PPA and expected to generate 152 GW-hrs annually. The facility will also generate Solar Renewable Energy Credits (SRECs) which will be sold into the Maryland market.

(iii) Completion of Morse Wind Facility

On April 22, 2015 the Renewable Generation Group completed construction of a 23 MW wind generating facility, located near Morse, Saskatchewan (the "Morse Wind Facility"). The facility is the Renewable Generation Group's eighth wind generating facility and consists of 10 2.3 MW direct drive wind turbine generators installed over 1,120 acres of land. The facility is expected to generate 104 GW-hrs of energy per year which is being sold under a 20 year PPA with a large investment grade electric utility.
(iv) Completion of Bakersfield I Solar Project

On April 14, 2015 the Renewable Generation Group achieved commercial operation in accordance with the provisions within the PPA on the 20 MW Bakersfield I Solar Facility located in Kern County, California. The facility is the Renewable Generation Group's second solar generating facility and is comprised of approximately 85,000 solar panels located on 165 acres of land. The project is expected to generate 53.3 GW-hrs of energy per year which is being sold under a 20 year PPA with a large investment grade electric utility.

Consistent with the commitment to expand its solar generation portfolio, the Renewable Generation Group announced that it was pursuing the construction of the 10 MW Bakersfield II Solar Facility immediately adjacent to the Bakersfield I Solar Facility. The Bakersfield II Solar Facility achieved commercial operations on January 11, 2017.

(v) Letter of Credit Facility

On October 30, 2015, the Renewable Generation Group entered into a new extendable one year letter of credit facility agreement (the "New Facility"). The New Facility expands the group's available liquidity by providing for issuances of letters of credit based on two separate tranches of Cdn $50.0 million and U.S. $30.0 million. Upon closing, certain letters of credit issued on the existing Renewable Generation Group credit facility were transferred to the New Facility.

Liberty Utilities Group

(i) Successful Rate Case Outcomes

A core strategy of the Liberty Utilities Group is to ensure an appropriate return on the rate base at its various utility systems. During 2015, the Liberty Utilities Group successfully completed several rate cases representing a cumulative annual revenue increase of approximately U.S. $18.1 million with the full annualized impact of these rate cases to be realized in 2016.

(ii) U.S. Debt Private Placement

On April 30, 2015, the Liberty Utilities Group financing entity entered into a Note Purchase Agreement for the issuance of U.S. $160.0 million of senior unsecured 30 year notes bearing a coupon of 4.13% via a private placement in the U.S. The proceeds of the financing were used to partially finance the acquisition of the Park Water System and for general corporate purposes. The notes were issued in two tranches: U.S. $90.0 million were issued immediately on closing and U.S. $70.0 million were issued on July 15, 2015. The notes were assigned a rating of BBB High by DBRS.

The financing is the fourth series of notes issued pursuant to the Corporation's master indenture.

(iii) Acquisition of New Hampshire Gas

On January 2, 2015, the EnergyNorth Gas System completed the acquisition of the New Hampshire Gas Corporation (the "New Hampshire Gas System"), a regulated propane gas distribution utility located in Keene, New Hampshire. The New Hampshire Gas System serves approximately 1,200 propane gas distribution customers. The total purchase price for the New Hampshire Gas System was approximately U.S. $3.16 million, subject to certain closing adjustments.

2.2.3 Fiscal 2016

Corporate

(i) Dividend Increased in Second Quarter 2016 to U.S. $0.4236 Per Common Share Annually

On May 12, 2016, the Board approved a dividend increase of U.S. $0.0384 per common share annually, bringing the total annual dividend to U.S. $0.4236 per common share, an increase of 10% over the previous dividend rate. The dividend increase reflected successful growth initiatives, including completion of the acquisition of Park Water, the announcement of the Corporation’s agreement to acquire Empire, and continued construction and development of new power generation facilities.

(ii) Dual Listing of Algonquin Common Shares on the New York Stock Exchange

During the fourth quarter APUC received approval to list its commons shares for trading on the New York Stock Exchange ("NYSE") under the ticker symbol "AQN". The Corporation has been a U.S. Securities and Exchange Commission ("SEC") registrant since 2009 and operates primarily in the United States. APUC shares continue to be listed on the Toronto Stock Exchange ("TSX") also under the ticker symbol "AQN".

(iii) U.S. $235 Million Corporate Term Credit Facility

On January 4, 2016, the Corporation entered into a U.S. $235.0 million term credit facility ("Corporate Term Facility") with two U.S. banks. The proceeds of the term credit facility provide the company with additional liquidity for general corporate purposes and acquisitions. The facility matures on July 5, 2018.
Renewable Generation Group

(i) Acquisition of 75% interest in the Red Lily I Partnership

Effective April 12, 2016, APUC, through its subsidiary, exercised its option to subscribe for a 75% equity interest in the Red Lily I Partnership, a 26.4 MW wind energy facility (the "Red Lily Wind Facility") located in southeastern Saskatchewan for which the Renewable Generation Group provides operation and supervision services. The equity interest was obtained in exchange for the outstanding amounts on two subordinated loans previously advanced by a subsidiary of the Corporation. Accordingly, effective the exercise date, the financial results of the Red Lily Wind Facility are reported as part of consolidated operations of APUC.

(ii) Completion of the Odell Wind Project

On July 29, 2016, the Odell Wind Facility achieved COD. The project consists of a 200 MW wind generating facility located in Cottonwood, Jackson, Martin, and Watonwan counties in Minnesota. On August 5, 2016, tax equity financing of approximately U.S. $180 million was completed. The Odell Wind Facility is the Renewable Generation Group's ninth wind generating facility and consists of 100 Vestas V110 2.0 wind turbines. The facility is expected to generate 831.8 GW-hrs annually. The project has a 20 year PPA with Northern States Power Company, a subsidiary of Xcel Energy Inc., which is a diversified utility operating in the Midwest U.S.

On September 15, 2016, the Corporation acquired the remaining 50% interest in Odell SponsorCo LLC for U.S $26.5 million and now controls the project.

(iii) Purchase of Turbines to Safe Harbour Production Tax Credit Rate

At the end of 2016, the Renewable Generation Group purchased approximately $75 million of turbine components ("Safe Harbor Turbines") that will qualify between 500 MW and 700 MW of new projects for 100% of the production tax credit ("PTC"). The full PTC is approximately U.S. $23 per MWh and subject to an annual adjustment for inflation. The PTC at the full rate is available to projects in the United States completed before the end of 2020 if they commenced construction prior to December 31, 2016 or have purchased components that qualify under the Internal Revenue Service ("IRS") safe harbor rules ("Full PTC Projects"). Projects other than Full PTC Projects will receive 80% of the applicable PTC rate if construction commences in 2017, 60% if construction commences in 2018, and 40% if construction commences in 2019. Securing access to the full PTC rate is an important competitive advantage in the U.S. market. The Renewable Generation Group is currently evaluating projects to maximize the value of this equipment.

Liberty Utilities Group

(i) Acquisition of the Park Water System

On January 8, 2016, the Liberty Utilities Group closed a previously announced agreement to acquire a regulated water distribution utility holding company, Park Water Company, now known as Liberty Utilities (Park Water) Corp. (the "Park Water System"). The acquisition of the Park Water System was originally announced in September 2014. 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.

Total consideration for the utility purchase was U.S. $341.3 million, which includes the assumption of approximately U.S. $91.8 million of existing debt. This acquisition maintains APUC's strategic business mix and further enhanced its investment grade consolidated capital structure.

The water utility located in western Montana is currently the subject of a condemnation lawsuit filed by the city of Missoula. Please see "4.2.2 Operational Risk - Regulatory Risk - Condemnation Expropriation Proceedings" and "9.2 Regulatory Actions" for a detailed description and discussion of the condemnation proceedings.

(ii) Successful Rate Case Outcomes

A core strategy of the Liberty Utilities Group is to ensure an appropriate return is earned on the rate base at its various utility systems. During 2016, the Liberty Utilities Group successfully completed several rate cases representing a cumulative annualized revenue increase of approximately U.S. $21.4 million. The Liberty Utilities Group has pending rate case filings in progress that represent an increase in rates in the amount of U.S. $14.1 million which are expected to be completed in 2017.

(iii) Completion of Phase I of the North Lake Tahoe Transmission System Upgrades

During 2016, the Liberty Utilities Group completed the rebuild of the 10 mile Northstar to Kings Beach, California transmission line for approximately U.S. $21.2 million. The rebuild involved an upgrade to 120 kv and will improve the reliability of the transmission system. The project is being completed in three phases and the total capital cost of the project will be included in the rate base of the utility. The second phase will result in an upgrade to substations and is expected to be in service in 2017.
2.3 Recent Developments - 2017

Corporate

(i) Completion of the Empire District Electric Acquisition

On January 1, 2017, APUC's wholly-owned regulated utility business successfully completed its acquisition of Empire for an aggregate purchase price of approximately U.S. $2.4 billion including the assumption of approximately U.S. $0.9 billion of debt.

Empire is a Joplin, Missouri based regulated electric, gas and water utility, that serves approximately 218,000 customers in Missouri, Kansas, Oklahoma, and Arkansas.

With the closing of the Empire Acquisition, APUC materially expanded its utility operations in the U.S. APUC, through its 2,200 employees, now serves over 783,000 electric, gas, and water customers within its regulated utility business, and APUC's portfolio of power generating facilities now contains both regulated and non-regulated power facilities with a total generating capacity of over 2,500 MW.

APUC expects that the Empire Acquisition will be accretive to earnings per common share in the first full year following closing and approximately 7% - 9% accretive to APUC's net earnings per common share over a three-year period following closing, excluding one-time acquisition-related expenses, and assuming a stable currency exchange environment. APUC also expects that the Empire Acquisition will be approximately 12% - 14% accretive to Adjusted Funds From Operations per common share over a three-year period following closing, excluding one-time acquisition-related expenses, and assuming a stable currency exchange environment. The increased contribution from regulated operations is also expected to further enhance the stability and predictability of Adjusted EBITDA, net earnings and quality of cash flows.

APUC has filed Form 51-102F4 dated March 10, 2017 in respect of the Empire Acquisition which may be found on SEDAR at www.sedar.com.

(ii) Annual Dividend Increased from U.S. $0.4235 to U.S. $0.4659 and Declaration of Canadian Equivalent First Quarter Dividend of Cdn $0.1533 (U.S. $0.1165) per Common Share

APUC currently targets a 10% annual growth in dividends payable to shareholders underpinned by increases in earnings and cashflow. Management believes that the increase in dividends is consistent with APUC's stated strategy of delivering total shareholder return comprised of attractive current dividend yield and capital appreciation.

In addition the completion of the Empire Acquisition in the first quarter of 2017, APUC has completed construction of new electric generating stations and has a number of electric generating stations in construction and under development. Collectively these growth initiatives have continued to raise the growth profile of the Company. As a result, on January 16, 2017, the Board approved a dividend increase of U.S. $0.0424 per common share annually, bringing the total annual dividend to U.S. $0.4659 per common share, an increase of 10% over the previous annual dividend rate.

Concurrently, APUC declared a first quarter 2017 dividend of U.S. $0.1165 per common share payable on April 14, 2017 to shareholders of record on March 31, 2017. Based on the Bank of Canada noon exchange rate on the declaration date, the Canadian dollar equivalent for the first quarter 2017 dividend is set at Cdn $0.1533 per common share.

The previous four quarter equivalent Canadian dollar dividends per common share have been as follows:

<table>
<thead>
<tr>
<th></th>
<th>Q2 2016</th>
<th>Q3 2016</th>
<th>Q4 2016</th>
<th>Q1 2017</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>U.S. dollar dividend</td>
<td>$0.1059</td>
<td>$0.1059</td>
<td>$0.1059</td>
<td>$0.1165</td>
<td>$0.4342</td>
</tr>
<tr>
<td>Canadian dollar equivalent</td>
<td>$0.1361</td>
<td>$0.1377</td>
<td>$0.1427</td>
<td>$0.1533</td>
<td>$0.5698</td>
</tr>
</tbody>
</table>

Strong Year of operating results

APUC recorded a strong twelve months of operations results relative to the same period last year.
(iii) Completion of Financing Related to the Empire Acquisition

$1.15 Billion Bought Deal Offering of Convertible Unsecured Subordinated Debentures Represented by Instalment Receipts

In the first quarter of 2016, in connection with the Acquisition, APUC and its direct wholly-owned subsidiary, LU Canada, entered into an agreement with a syndicate of underwriters under which the underwriters agreed to buy, on a bought deal basis, $1.15 billion aggregate principal amount of 5.00% convertible unsecured subordinated debentures ("Debentures") of APUC (the "Debenture Offering").

Following the closing of the Acquisition, the final instalment date was established as February 2, 2017 at which time APUC received the final instalment payment. To date, approximately 99.1% of the Debentures have been converted into common shares of APUC, with APUC issuing approximately 107,517,895 common shares as a result of the conversion. The proceeds were used to repay a portion of APUC's bank facility drawn at closing of the Acquisition ("Empire Acquisition Facility").

U.S. $750 Million Private Placement Offering

On March 1, 2017, Liberty Utilities Group's financing entity entered into an agreement to issue U.S. $750 million of senior unsecured private placement notes to 29 institutional investors in the U.S. and Canada. The notes are of varying maturities from 3 to 30 years with a weighted average life of approximately 15 years and a weighted average coupon of 3.6% after considering the effects of interest rate hedges entered into in 2016. The closing of the offering is scheduled to occur on March 24, 2017, with the proceeds to be used to repay the balance of the Empire Acquisition Facility and other existing indebtedness.

Renewable Generation Group

(i) Completion of the Deerfield Wind Project

Subsequent to year end, on February 21, 2017, the Deerfield Wind Facility achieved COD. The project consists of a 150 MW wind generating facility located in central Michigan. The Deerfield Wind Facility is the Renewable Generation Group's tenth wind generating facility and consists of 44 Vestas V110-2.0 wind turbines and 28 Vestas V110-2.2 turbines and is estimated to generate 555.2 GW-hrs annually. The project has a 20 year PPA with a local electric distribution utility serving approximately 260,000 customers in Michigan.

(ii) Completion of the Bakersfield II Solar Project

On January 11, 2017, the Renewable Generation Group achieved COD on the 10 MWac solar generating facility located in Kern County, California (the "Bakersfield II Solar Facility"). On February 28, 2017, tax equity financing of approximately U.S. $12.3 million was completed. The Bakersfield II Solar Facility is the Renewable Generation Group's third solar generating facility and is comprised of approximately 38,640 solar panels located on 64 acres of land. The project is expected to generate 24.2 GW-hrs of energy annually. The project has a 20 year PPA with a large investment grade electric utility in California.

(iii) Issuance of $300 million Senior Unsecured Debentures

On January 17, 2017, the Renewable Generation Group issued $300.0 million of senior unsecured debentures bearing interest at 4.09% and with a maturity date of February 17, 2027. The debentures were sold at a price of $99.929 per $100.00 principal amount. Concurrent with the offering, the Renewable Generation Group entered into a cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated offering into U.S. dollars.

The net proceeds have been used to partially finance the Odell Wind Facility, Deerfield Wind Facility and Bakersfield II Solar Facility.

Liberty Utilities Group

(i) Completion of the Luning Solar Project.

Subsequent to year end, on February 15, 2017, the Liberty Utilities Group obtained control of a 50 MW solar generating facility located in Mineral County, Nevada for approximately U.S. $110.9 million. The facility is comprised of approximately 204,784 solar panels located on 584 acres of land. The project is expected to generate 144.6 GW-hrs of energy annually. On February 17, 2017, tax equity financing of approximately U.S. $39.0 million was completed. The net capital cost of the project will be included in the rate base of the CalPeco Electric System as energy produced from the project will be consumed by the utility's customers.
3. DESCRIPTION OF THE BUSINESS

3.1 Renewable 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 Corporation operates has various pieces of legislation in effect with which the business must comply. 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 (the "ISO") 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 Corporation 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 FERC under the U.S. Federal Power Act ("FPA"), the 2005 Energy Policy Act, the Public Utilities Regulatory Policies Act (PURPA) and the Public Utility Holding Company Act of 2005 ("PUHCA").

(1) Rate Regulation

All of the Renewable Generation Group's operating U.S. 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 of the Renewable Generation Group's operating U.S. 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, unless within a certain geographic proximity of one another. 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) NERC

The 2005 Energy Policy Act expanded FERC's authority to impose mandatory reliability standards on the bulk electric system and to impose penalties on entities that manipulate the electric and natural gas markets. On June 20, 2006, the North American Electric Reliability Corporation (NERC) was certified by FERC as the Electric Reliability Organization (ERO) for North America. NERC's mission is to ensure the reliability and security of the North American Bulk Electric System. NERC accomplishes its mission through enforcement of mandatory regulation of reliability operating standards. NERC also annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel. NERC’s area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is subject to oversight by FERC and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the bulk power system, which serves more than 334 million people. Some assets of the Renewable Generation Group and the Liberty Utilities Group are subject to regulation by NERC.
(3) 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 Renewable Generation Group’s intermediate holding companies claims exemption from PUHCA under Title 18, Part 366.3 of the U.S. Code of Federal Regulations (CFR), 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 Renewable 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 (“Alberta Power Pool”) was established under the EUA to provide a competitive, real-time spot market for electric energy. The Alberta 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 Alberta Power Pool.

(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 (‘OECF’) purchases the energy generated by the Ontario facilities and holds all rights, obligations and liabilities under 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. It also sells power on wholesale markets in northeastern North America.

(iii) Material Facilities

(1) Long Sault Hydro Facility

The Long Sault Hydro Facility is a run-of-river 18 MW hydroelectric generating facility consisting of four 4,500 kilowatt pit turbine generating units located on the Abitibi River, 19 kilometres north of the Town of Cochrane, in northern Ontario.

The Long Sault Hydro Facility was commissioned in 1998. The facility was developed by a joint venture between wholly-owned subsidiaries of APUC and N-R Power Partnership, an unrelated third party (the “Co-Owners”). There is a non-recourse loan outstanding which is secured against the facility and the Co-Owners’ interests therein.

The Long Sault Hydro Facility has entered into a 50 year PPA with OEFC effective April 1, 1998 under which all electricity produced at the facility is sold to the OEFC. The PPA 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 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 which commenced in January 2008.

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.

There is an outstanding senior loan against the facility in the amount of $33.5 million as at December 31, 2016. The loan matures in January 2028 and bears interest at an interest rate of 10.21% compounded annually for the balance of the loan. Blended payments of principal and interest are made monthly. The loan is non-recourse and is secured by the facility and the ownership interests therein.

(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 by way of a lease agreement with the St. Lawrence Seaway Authority. 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 section 9.1, “Legal Proceedings.”

The Côte Ste. Catherine Hydro Facility 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.

APUC is currently in negotiations with Hydro-Québec to renegotiate pricing for the extension period of the PPAs related to a number of other Québec-based hydro sites.

(3) 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 approximately 34.5 MW.

The Tinker Hydro Facility was acquired by APUC on January 13, 2010.
As part of the generation assets in New Brunswick and Northern Maine, APUC owns an electrical transmission system consisting of 14.7 kilometres 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. As part of the recent filings under the Electricity Act (New Brunswick), Tinker Gen Co. sought two initiatives under Matter 256; to secure pre-authorization of a transformer upgrade and to establish an updated revenue requirement for the transmission service function. On March 24, 2016, the New Brunswick Energy and Utilities Board (the “NBEUB”) issued an order in Matter 256 authorizing an increase in the Tinker Hydro Facility annual revenue requirement to $0.9 million. This approval does not contain any additional revenue requirement for the transformer upgrade authorized in the EUBNB’s September 2015 order. Since the third quarter of 2016, the Tinker Hydro Facility has been installing the authorized transformer upgrades following the receipt of all necessary permits issued. Tie-ins are being coordinated with affected stakeholders in New Brunswick. Following the start of service, the Tinker Hydro Facility will submit a request to increase its revenue requirement for the additional $12.0 million of capital investment.

The output of the Tinker Hydro Facility is actively marketed along with certain other owned assets of the Corporation which sell the energy they generate together with any applicable environmental attributes less any associated transportation costs. The Corporation provides energy to commercial and industrial customers in the Northern Maine markets primarily by selling energy from the Tinker Hydro Facility.

Additional energy and applicable environmental attributes are purchased from the market to supplement the energy generated from the Tinker Hydro Facility in order to service customer demand, and from time to time it sells any excess generation to the market. Risk associated with energy sold in excess of what is generated by the Tinker Hydro Facility is managed through the purchase of fixed volume/prices from the market. In addition, APUC 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.

(4) Dickson Dam Hydro Facility

The Dickson Dam Hydro Facility is located 20 kilometres west of the Town of Innisfail, Alberta. The Dickson Dam Hydro Facility is a 15.0 MW hydroelectric generating facility utilizing the infrastructure located at the Dickson Dam and powered by the water flows of the Red Deer River.

The Dickson Dam Hydro Facility was commissioned on January 16, 1992.

APUC sells all of the power generated at the Dickson Dam Hydro Facility in the Alberta Power Pool at market rates.

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 favour 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 and Morse Wind Facilities, and Quebec for the Saint-Damase Wind Project. 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 and Morse Wind Facility, and Hydro Quebec in the case of the Saint-Damase Wind Project. 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 LLC (“PJM”), Midcontinent Independent System Operator, Inc. (“MISO”) and Electric Reliability Council of Texas (“ERCOT”) regional markets.
(1) Manitoba
Historically, Manitoba Hydro had been exclusively responsible for the production of electricity in the province. Manitoba Hydro is a net exporter of electricity, mainly to Ontario and certain states of the United States. To date, the province has been able to utilize its large hydroelectric resources to satisfy internal and export requirements.

(2) Saskatchewan
Saskatchewan’s electricity market remains under provincial government control and has not undergone any significant deregulation. SaskPower, the primary electricity utility in Saskatchewan, is wholly-owned by the province through the Crown Investments Corporation. SaskPower has set a target of 50% of generation capacity from renewables by 2030. 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 for 99% of electricity mix, and as such, the utility has encouraged the development of wind projects in the province in recent years. Hydro-Québec’s previous wind project calls for tenders have resulted in over 3,000 MW of wind capacity to be installed in the province. In addition, another 275 MW of wind are under construction and another almost 400 MW are planned.

(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) Michigan and Minnesota
The Midcontinent Independent System Operator (“MISO”) is an 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 (“NERC”) 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 St. Leon Wind Facility achieved commercial operation on April 1, 2006 and entered into a PPA with Manitoba Hydro effective June 17, 2006 under which all electricity produced is sold to Manitoba Hydro. The term of the PPA is 20 years, with a price renewal term of up to an additional 5 years.

(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. The St. Leon II Wind Facility achieved commercial operations on March 1, 2012 and entered into a 25 year PPA with Manitoba Hydro effective July 1, 2012 under which all electricity produced is sold to Manitoba Hydro.
(3) Red Lily I Wind Facility

The Red Lily Wind Facility is a 26.4 MW wind energy facility located 5 km west of Moosomin, Saskatchewan. The Red Lily Wind Facility achieved commercial operation on February 28, 2011 and has a PPA with SaskPower with a term of 25 years from commencement of commercial operation and includes a 2% annual increase throughout the term of the agreement.

All of the equity in the Red Lily Wind Facility was initially owned by an independent investor, Concord Pacific Group. APUC’s investment in the Red Lily Wind Facility was initially in the form of participation in a portion of the senior debt facility, and a subordinated debt facility to the Red Lily Partnership. In addition to the loans extended by APUC, an additional $31.0 million of senior debt has been provided by a third party lender.

On February 23, 2016, a second tranche of subordinated loan for an amount equal to $15.6 million was advanced by APUC. The proceeds from this additional subordinated debt were used by the Red Lily Wind Facility to repay Tranche 2 of the Red Lily Partnership’s senior debt, including the Corporation’s portion. On March 1, 2016, the Corporation exercised its option to formally exchange its debt investment and fee interest in the project for a 75% equity interest. The Concord Pacific Group retains a 25% ownership interest in the project. The earnings of the Red Lily Wind Facility are not consolidated into the financial statements of the Corporation and are instead accounted for using the equity method.

(4) Morse Wind Facility

The Morse Wind Facility is a 23 MW wind energy facility located near Morse, Saskatchewan, approximately 180 km west of Regina. The facility achieved commercial operation on April 22, 2015. The Morse Wind Facility has a PPA with SaskPower under the Green Options Partner Program with a term of 20 years.

(5) Saint-Damase Wind Project

The Saint-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. The facility was developed in partnership with the Municipality of Saint-Damase. The Saint-Damase Wind Facility achieved commercial operations on December 2, 2014 and has entered into a 20 year PPA with Hydro-Québec beginning on this date.

(6) 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 was acquired by the Corporation on January 1, 2013. The facility reached commercial operation in June 2012.

The Shady Oaks Wind Facility is party to 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.

(7) 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. APUC first acquired an indirect interest in the Sandy Ridge Wind Facility on July 1, 2012. The Sandy Ridge Wind Facility reached commercial operation in February, 2012.

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

(8) Minonk Wind Facility

The Minonk Wind Facility is a 200 MW wind energy facility located near Minonk, IL, 200 km southwest of Chicago, IL. APUC first acquired an indirect interest in the Minonk Wind Facility on December 10, 2012. The Minonk Wind Facility reached commercial operation in December 2012.

Minonk Wind, LLC is party to the Primary Energy Production Hedge with JPMVEC, having a term of 10 years beginning January 1, 2013. Based on the JPMVEC contract quantity, approximately 73% of energy revenues are expected to be earned under the Primary Energy Production Hedge. Ancillary services, including capacity and RECs, are sold into the energy market in which the Minonk Wind Facility is registered.
(9) Senate Wind Facility
The Senate Wind Facility is a 150 MW wind energy facility located near Graham, Texas, 200 km west of Dallas, Texas. APUC first acquired an indirect interest in the Senate Wind Facility on December 10, 2012. The Senate Wind Facility reached commercial operation in December 2012.

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

(10) Odell Wind Facility
The Odell Wind Facility is a 200 MW wind facility located near Windom, Minnesota, 230 km southwest of Minneapolis, Minnesota. The Odell Wind Facility reached commercial operation on July 29, 2016.

Odell Wind Farm LLC has entered into a PPA with Northern States Power Company under which all electricity and RECs produced at the facility are sold to Northern States Power Company. The term of the PPA is 20 years.

(11) Deerfield Wind Facility
The Deerfield Wind Facility is a 149.0 MW wind energy facility located in central Michigan, 180 km north of Detroit, Michigan. APUC first acquired an indirect interest in the Deerfield Wind Facility on October 19, 2015. The Deerfield Wind Facility reached commercial operation in February, 2017.

All energy, capacity, and renewable energy credits from the project are sold to a local electric distribution utility, which serves 260,000 customers in Michigan, pursuant to a 20 year PPA.

(iv) Renewable Energy Credits
RECs are tradeable commodities representing the generation of 1 MW-hr 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. Currently, 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, Bakersfield I Solar Facility and the Bakersfield II Solar Facility utilize 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 and the Bakersfield II 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 ISO.

(1) Ontario
The Independent Electricity System Operator (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 OEB and 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 FERC. The CAISO operates as a non-profit 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 ground mounted photovoltaic solar energy facility located near Cornwall, Ontario, 100 km southeast of Ottawa. The facility achieved commercial operation on March 27, 2014.

The Cornwall Solar Facility has a FiT contract with the IESO with a term of 20 years with a fixed power purchase rate throughout the term.

(2) **Bakersfield I Solar Facility**

The Bakersfield I Solar Facility is a 20 MW 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 I Solar Project achieved commercial operation in April 2015 and has a PPA with Pacific Gas and Electric Company ("PG&E") with a term of 20 years from commencement of commercial operation. The PPA has a fixed power purchase rate throughout the term.

(3) **Bakersfield II Solar Facility**

The Bakersfield II Solar Facility is a 10 MW 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, adjacent to the Bakersfield I Solar Facility.

The Bakersfield II Solar Project achieved commercial operation in January 2017 and has a PPA with a large investment grade electric utility in California with a term of 20 years from commencement of commercial operation.

**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. 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.

(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 ISO 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 ("CPUC") and FERC. The CAISO 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"). 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.

(iii) **Material Facilities**

(1) **Sanger Thermal Facility**

The Sanger thermal cogeneration facility (the "Sanger Thermal Facility") is a 56MW natural gas-fired generating facility located in Sanger, California. The Sanger Thermal Facility was acquired by APUC on May 1, 2002.

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. The Sanger Thermal Facility has a firm capacity and energy PPA with PG&E expiring in 2021. The agreement calls for delivery of 38 MW of firm capacity.
(2) Windsor Locks Thermal Facility

The Windsor Locks thermal cogeneration facility (the "Windsor Locks Facility") is a 71 MW natural gas-fired generating facility located in Windsor Locks, Connecticut. The facility was acquired by APUC on March 10, 2003.

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 supplies thermal steam energy and the majority of the output from the Solar Titan combustion turbine to Ahlstrom Corporation ("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.

(iv) Renewable Energy Credits

RECs are tradable commodities representing the generation of 0.75 MW-hr of electricity, and are used by utilities to satisfy compliance with RPS where necessary. Currently, the Windsor Locks Thermal Facility is qualified for Class III CT RECs. It produces and sells RECs through bilateral contracts.

Business Development

(i) Strategy

The Development Division works to identify, develop and construct new power generating facilities, as well as to identify, and acquire operating projects that would be complementary and accretive to the Group’s existing portfolio. The Development Division is focused on projects within North America and is committed to working proactively with all stakeholders including local communities. The Renewable Generation Group’s approach to project development and acquisition is to maximize the utilization of internal resources while minimizing external costs. This allows projects to mature to the point where most major elements and uncertainties are quantified and resolved prior to the commencement of project construction. Major elements and uncertainties of a project include the signing of a PPA, obtaining the required financing commitments to develop the project, completion of environmental and other required 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 the Renewable Generation Group’s Development Division will begin construction or execute an acquisition agreement.

(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 Alberta and Saskatchewan are expected to present the most immediate opportunities for the corporation. The Alberta Electric System Operator ("AESO") was commissioned by the Government of Alberta to develop recommendations for the procurement of renewable sources of power that will allow the province to meet its objective to have 30 per cent of electricity generation by 2030 come from renewable sources. The AESO’s recommendations were endorsed by the Government of Alberta on November 3, 2016, resulting in the formation of the Renewable Electricity Program ("REP"), which is expected to lead to the development of 5,000 MW of renewable energy capacity by 2030. The first competitive solicitation is expected to commence in early 2017, with contracts awarded by the end of 2017.

In Saskatchewan, the vertically-integrated utility SaskPower has set a target of 50% of generation capacity to come from renewables by 2013, which is expected to lead the development of approximately 1,600 MW of new wind energy generation and 120 MW of utility-scale solar generation. The first competition is expected to commence in early 2017, with contracts awarded by the end of 2017. Nova Scotia also continues to offer its community FIT 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. On December 18th, 2015, the United States Congress approved a five-year extension to the 30 percent ITC for solar energy properties and 2.3 cents per kilowatt-hour PTC for wind
facilities. The ITC for solar energy will remain at 30 percent through 2018, before it phases down gradually to 10 percent in 2022. The PTC for wind energy will be at maintained at 2.3 cents per kilowatt-hour for projects on which construction is commenced prior to the end of 2016 before phasing down 20 percent per year and being eliminated at the end of 2019. Additionally, other 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 RPS, which vary between states. As of 2016, 29 states plus Washington D.C. and three territories have adopted binding RPS targets, and eight additional states have taken on voluntary renewable portfolio goals. These targets range between 10% and 50% of retail sales to specific entities, to be achieved between 2015 and 2040.

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

(iii) Current Development Projects

The Renewable Generation Group's Development Division has successfully advanced a number of projects and has been awarded or acquired a number of PPAs. All of the projects contained in the table below meet the following criteria: a proven wind or solar resource, a signed PPA with a credit-worthy counterparty, and projected investment returns that meet or exceed the Corporation's investment return criteria.

<table>
<thead>
<tr>
<th>Project Name</th>
<th>Location</th>
<th>Size (MW)</th>
<th>Estimated Capital Cost (millions)$1</th>
<th>Commercial Operation</th>
<th>PPA Term</th>
<th>Production GW-hrs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Projects in Construction</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Amherst Island Wind Project</td>
<td>Ontario</td>
<td>75</td>
<td>295</td>
<td>2018</td>
<td>20</td>
<td>235</td>
</tr>
<tr>
<td>Great Bay Solar Project1</td>
<td>Maryland</td>
<td>75</td>
<td>195</td>
<td>2017</td>
<td>10</td>
<td>146</td>
</tr>
<tr>
<td>Total Projects in Construction</td>
<td></td>
<td>150</td>
<td>$490</td>
<td></td>
<td></td>
<td>381</td>
</tr>
<tr>
<td>Projects in Development</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Chaplin/Blue Hill Wind Project</td>
<td>Saskatchewan</td>
<td>177</td>
<td>345</td>
<td>2019/20</td>
<td>25</td>
<td>813</td>
</tr>
<tr>
<td>Val-Eo Wind Project2</td>
<td>Quebec</td>
<td>24</td>
<td>65</td>
<td>2018</td>
<td>20</td>
<td>879</td>
</tr>
<tr>
<td>Total Projects in Development</td>
<td></td>
<td>201</td>
<td>$410</td>
<td></td>
<td></td>
<td>879</td>
</tr>
<tr>
<td>Total in Construction and Development</td>
<td></td>
<td>351</td>
<td>$900</td>
<td></td>
<td></td>
<td>1,260</td>
</tr>
</tbody>
</table>

1 The total cost of the project is expected to be approximately $145 million in U.S. dollars.
2 All figures refer solely to Phase I of the Val-Eo Wind Project.
3 Estimated capital costs for U.S. based projects have been converted at the exchange rate in effect at the end of the current reporting period.

(1) Amherst Island Wind Project

The Amherst Island Wind Project is a 75.0 MW wind powered electric generating development project located on Amherst Island near the village of Stella, approximately 15 kilometers southwest of Kingston, Ontario.

The project is currently contemplated to use Class III wind turbine generator technology consisting of 26 Siemens 3.0 MW turbines and is expected to produce approximately 235.0 GW-hrs of electrical energy annually with all energy being sold under a 20 year PPA awarded as part of the Independent Electricity System Operator ("IESO"), formerly the Ontario Power Authority, Feed in Tariff ("FIT") program.

The total cost to complete the project is estimated at approximately $295 million.

The Renewable Energy Approval ("REA") was issued on August 24, 2015 following 29 months of review by the Ontario Ministry of Environment. An appeal of the REA was made to the Environmental Review Tribunal ("ERT") in 2015. The ERT decision to uphold the REA was issued on August 3, 2016. The project has since conducted final development and procurement efforts and is now under construction. A Divisional Court challenge of the favorable ERT decision was dismissed in the first quarter of 2017.

Since the REA decision, the Corporation procured the project turbines, submarine cable, and the main power transformer. Negotiations are in progress to engage the balance of plant constructor. Subject to receipt of final permits and negotiation of remaining agreements, final development and construction is expected to be complete in the second quarter of 2018.
(2) Great Bay Solar Project
The Great Bay Solar Project is a 75.0 MW solar powered electric generating development project located in Somerset County in southern Maryland.

The facility is comprised of 300,000 solar panels and is being constructed on 400 acres of land. The project is expected to generate 146.0 GW-hrs of energy per year, with all energy sold to the U.S. Government Services pursuant to a 10 year PPA, with a 10 year extension option. All Solar Renewable Energy Credits from the project will be retained by the project company and sold into the Maryland market.

Permitting with the county is underway and is expected to be completed in the first quarter of 2017. The project has received its Certificate of Public Convenience and Necessity from the State of Maryland Public Service Commission. The balance of plant and high voltage engineering, procurement, and construction contracts have been executed. The project has a commercial operations date targeted for the end of 2017.

The total costs to complete the project are estimated at approximately U.S. $145.0 million. The Renewable Generation Group expects the project will qualify for U.S. federal investment tax credits and accordingly, approximately 40% of the permanent project financing is expected to be funded by tax equity investors in return for the majority of the tax attributes.

(3) Chaplin-Blue Hill Wind Project
The Chaplin-Blue Hill Wind Project is a 177.0 MW wind powered electric generating development project located in Saskatchewan. All of the energy from the project will be sold to SaskPower pursuant to a 25 year PPA awarded in 2012. The project was originally located in the rural municipality of Chaplin, Saskatchewan, 150 km west of Regina, Saskatchewan.

During the year the Saskatchewan Ministry of the Environment determined the original location proposed for the project did not meet its new siting guidelines for wind farms in the Province. As a result, SaskPower and the Corporation have worked to reconfigure the project in a manner that meets new siting guidelines in the rural municipalities of Morse and Lawtonia.

The Chaplin-Blue Hill project will be developed as a single phase installation beginning in early 2019. All energy from the facility will be sold to SaskPower pursuant to a 25 year PPA that was signed in December 2016. The project requires final environmental approval and all other necessary permitting.

The total costs to complete the project are estimated at approximately $345.0 million but are subject to change depending on turbine selection.

(4) Val-Éo Wind Project
The Val-Éo Wind Project is a 125 MW wind powered electric generating development project located in the local municipality of Saint-Gideon de Grandmont, which is within the regional municipality of Lac-Saint-Jean-Est, Quebec. The project proponents include the Val-Éo Wind Cooperative which was formed by community based landowners and the Renewable Generation Group.

The Renewable Generation Group’s equity interest in the project is subject to final negotiations with the Val-Éo community cooperative but, in any event, will not be less than 25%. It is believed that the first 24 MW phase of the Val-Éo 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.

The project will be developed in two phases: Phase I of the project is expected to be completed in 2018 and will likely be comprised of ten 2.35 MW wind turbines for a total capacity of 24 MW and is expected to generate 66.0 GW-hrs of energy per year, with all energy from Phase I of the project to be sold to Hydro-Quebec pursuant to a 20 year PPA; Phase II of the project would entail the development of an additional 101 MW and would be constructed following the successful evaluation of the wind resource at the site, completion of satisfactory permitting and entering into appropriate energy sales arrangements.

All land agreements, construction permits, and authorizations have been obtained for Phase I. The new schedule calls for Phase I construction to begin in the spring of 2017, with commissioning to occur in 2018.

(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 Renewable 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 Renewable Generation Group requires specialized knowledge of hydraulic turbines and their various components. This specialized knowledge is available to the Renewable Generation Group in-house.

The energy from wind aspect of the business of the Renewable Generation Group requires specialized knowledge of wind turbines and their various components. This specialized knowledge is available to the Renewable Generation Group in-house.

On a more general level, the production of energy from all facilities requires specialized skill and knowledge, and the Renewable 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 U.S. Department of Energy (“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 has generally been more expensive than traditional forms of generated power. However, in recent years costs have decreased with the increased demand for renewable energy, market competitiveness and improvements in generating technology. With production tax incentives, investment tax incentives, RPS, and improved equipment capacity factors, both wind and solar energy have achieved 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 Renewable 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 Renewable 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) Solar Power Generating Facilities

The Renewable 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.

The Company attempts to mitigate the above noted natural resource fluctuation risks by acquiring or developing generating stations in different geographic locations.

3.1.6 Customers

Please see “Enterprise Risk Factors – Treasury Risk Factors – Credit-Counterparty” for a detailed description and discussion of the most significant customers of the Renewable Generation Group.

3.2 Liberty Utilities Group

3.2.1 Regulatory Regimes - Utility Distribution Systems

Investor-owned utilities, whether water distribution and wastewater 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 Wastewater 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 Public Convenience and Necessity ("CPCN") which imposes an exclusive right and duty to serve in the service territory. A CPCN 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 Corporation'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 CPCN 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 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 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 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 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 fees and reconnects.

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 Corporation's water and wastewater facilities are located in the United States of America in the states of Arizona, Texas, Illinois, Missouri, Arkansas, and with the recent acquisition of Park Water, 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 Corporation 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. Rates are approved by the agency to provide the utility the opportunity, but not the guarantee, to earn a reasonable return on its investment after recovering its prudently incurred operating expenses. A summary of the rates and tariffs for the wastewater treatment and water distribution utilities 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 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 APSC 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 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 primary jurisdiction for all water service providers, including those owned and operated by municipalities. The jurisdiction respecting drinking water for CPUC-regulated water providers is shared between the CPUC and SWRCB pursuant to a Memorandum of Understanding. The SWRCB is the primary regulator for all discharge permits from drinking water systems in California.

(5) Montana

The Montana Public Service Commission ("MTPSC") 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 wastewater treatment facility ("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 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 22,300 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 95% of design capacity. Construction began in April 2016 to expand the treatment capacity from 4.2 million gallons per day to 5.6 million gallons per day. Construction will finish in 2017.

Rate Case
On February 28, 2013, the LPSCo System filed a general rate case with the ACC 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 ACC approved a $1.8 million increase in rates effective on May 1, 2014.

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

Connection Base
The Rio Rico System serves approximately 7,000 water and 2,300 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.

Rate Case
On October 28, 2015, the Rio Rico Water and Wastewater System filed a rate case and financing application. The application seeks a combined increase in revenue requirement of U.S. $0.9 million, based on a test year ending December 31, 2014, a combined rate base of U.S. $14.2 million, a 10.8% return on equity ("ROE") and 70% equity. The proposed revenue increases are U.S. $0.7 million, or 22.6%, for the water division and U.S. $0.2 million, or 15.3%, for the wastewater division. This rate case sought to recover increased operating costs and capital improvements. The rate case also sought approval for the fair value Arizona rate evaluation model ("FARE"), a purchased power adjuster mechanism ("PPAM") and a property tax adjuster mechanism ("PTAM"). The FARE allows for a periodic update of all components in the revenue requirement (subject to an earnings band). A Comprehensive Settlement Agreement was filed in July 2016, supporting a 9.7% ROE, 70% equity, and a U.S. $0.98 million revenue increase. A Recommended Opinion and Order ("ROO") was issued in October 2016 accepting the settlement. A final decision was issued on October 27, 2016 approving the settlement, with implementation of new rates in November 2016. The previous rate case was based on a test year ending February 2012. 
(4)  Black Mountain Sewer System
The Black Mountain sewer system (the "Black Mountain System") is a wastewater facility located in Carefree, Arizona.

Connection Base
The Black Mountain System serves approximately 2,500 wastewater connections in the community of Carefree, Arizona.

Rate Case
On June 22, 2015, the Black Mountain Wastewater System filed a rate case and financing application. The application seeks an increase in revenue requirement of U.S. $0.4 million, or 18.75%, based on a test year ending December 31, 2014. This rate case is primarily designed to resolve issues related to rate design and the closure of the treatment plant. No amounts have been removed from rate base in this application. The increase reflects a requested return on equity of 10.8% and a debt/equity structure of 30%/70%. An all-party settlement has been achieved and was filed on January 22, 2016. The settlement includes a revenue increase of U.S. $0.2 million, premised upon a 9.5% return on equity on 70% of capital. A Recommended Opinion and Order was issued on March 25, 2016 approving the settlement and implementation of new rates as of May 1, 2016, much earlier than originally expected.

(5)  Bella Vista Water System
The Bella Vista water system (the "Bella Vista System") is a regulated water utility in Sierra Vista, Arizona.

Connection Base
The Bella Vista System serves approximately 9,700 water connections in the community of Sierra Vista, Arizona.

Rate Case
On October 28, 2015, the Bella Vista Water System filed a rate case and financing application. The application sought an increase in revenue requirement of U.S. $1.6 million, or 33.6%, based on a test year ending December 31, 2014, a rate base of U.S. $13.2 million, 11.6% ROE, and 70% equity. This rate case seeks to recover increased operating costs and capital improvements. It also includes approval for the FARE, a PPAM and a PTAM. A Comprehensive Settlement Agreement was filed in July 2016, supporting a 9.7% ROE, 70% equity, and a U.S. $0.96 million revenue increase. A ROO was issued in October 2016 accepting the settlement. A final decision was issued on October 27, 2016 approving the settlement, with implementation of new rates in November 2016. The previous rate case was based on a test year ending March 2009.

Financing
Outstanding third party indebtedness at The Bella Vista Water System consists of U.S. $0.7 million of Water Infrastructure Financing Authority of Arizona loans bearing interest rates of 6.26% and 6.10% and maturing March 1, 2020 and December 1, 2017, respectively. The loans have principal and interest payments, payable monthly and quarterly in arrears. On February 8, 2017, all remaining principal on the Bella Vista Water unsecured notes were fully repaid.

(6)  Pine Bluff Water System
The 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 PSC and has a franchise agreement with the City of Pine Bluff, Arkansas.

Connection Base
The Pine Bluff Water System serves a population of over 47,000 people comprising approximately 18,800 connections. During the year ended December 31 2016, the Pine Bluff Water System's largest 10 connections represent approximately 24% of its total annual sales of approximately US$9.9 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 Arkansas PSC 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. The case has concluded and an Order was issued on March 12, 2015, approving a U.S. $1.1 million revenue increase effective March 15, 2015.

(7)  Park Water System
On January 08, 2016, the Liberty Utilities Group closed a previously announced agreement with Western Water Holdings, a wholly-owned investment of Carlyle Infrastructure, to acquire the regulated water distribution utility, Park Water Company, now known as Liberty Utilities (Park Water) Corp. ("Park Water"). Park Water owns and operates three regulated water utilities
engaged in the production, treatment, storage, distribution, and sale of water in Southern California and Western Montana. Park Water provides, owns and operates the water system in central Los Angeles. Apple Valley Ranchos Water Company, now known as Liberty Utilities (Apple Valley Ranchos Water) Corp. (“Apple Valley”), owns and operates the water system in Apple Valley, California. Mountain Water Company (“Mountain Water”) owns and operates the water system serving the municipality of Missoula, Montana. Mountain Water and Apple Valley are wholly-owned by Park Water.

Connection Base

The three utilities collectively serve approximately 70,700 customer connections and have more than 1,000 miles of distribution mains.

Mountain Water Company is currently the subject of a condemnation lawsuit filed by the city of Missoula. Please see “4.2.2 Operational Risk - Regulatory Risk - Condemnation Expropriation Proceedings” and “9.2 Regulatory Actions” for a detailed description and discussion of the condemnation proceedings.

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, New Hampshire, Missouri, Arkansas, Oklahoma and Kansas 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 Corporation operates electrical distribution systems in the states of Arkansas, California, Kansas, Missouri, New Hampshire and Oklahoma under a cost-of-service methodology. The utilities use either an historical test year, pro-formed for known and measurable changes, in the establishment of their rates, or prospective test years based on expenses expected to be incurred in future periods, which is the methodology utilized in California. Pursuant to these methods, 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 Corporation 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 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 (“PTYAM”) 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 $4.5 million or $53.4 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, steam, 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.

(3) Missouri (as of January 1, 2017 following the Empire Acquisition)

The Corporation's Missouri operations are regulated by the MPSC. The rates and fees for providing electric 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 fuel costs are charged through the Fuel Adjustment Clause (“FAC”).

(4) Arkansas (as of January 1, 2017 following the Empire Acquisition)

The Arkansas PSC is the primary regulatory agency with jurisdiction over the investor owned electric utilities in Arkansas for rates and charges.

(5) Oklahoma (as of January 1, 2017 following the Empire Acquisition)

The Corporation Commission of Oklahoma (“OCC”) is the primary regulatory agency with jurisdiction over rates and charges of investor owned utilities in Oklahoma.

(6) Kansas (as of January 1, 2017 following the Empire Acquisition)

The State Corporation Commission of the State of Kansas (“KCC”) is the primary regulatory agency with jurisdiction over rates and charges of investor owned utilities in Kansas.

(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 48,800 connections.

Connection Base

CalPeco Electric System's connection base of approximately 48,800 connections is primarily residential with large commercial accounts limited to less than 18% 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 9.3% of its total annual sales of approximately U.S. $82.7 million. Its largest customers are major ski resorts and large region school district.

Rate Case

On May 1, 2015, the CalPeco Electric System filed an application with the CPUC seeking an increase in revenue of U.S. $13.6 million (of which U.S. $11.4 million related to an increase in distribution margin revenue, and the remainder related to energy costs and other non-distribution charges), or 17.3%, based on a test year ending December 31, 2014, with pro forma changes to certain operating expenses and rate base capital additions. The increase reflects a requested 10.5% ROE, and 55% equity. The previous test year ended December 31, 2011. In May 2016, an all-party settlement was filed with the CPUC allowing for a U.S. $9.8 million net distribution margin revenue increase, or approximately 86% of the requested
increase. The increase reflects a 10.0% ROE and 52.5% equity. A final permanent rate decision from the CPUC was received in the fourth quarter of 2016, approving the settlement with a revision to the treatment of tax repairs in rates. This revision lowered the approved revenue increase to U.S. $8.3 million. The new permanent rates were implemented January 2017, and reflect retroactive effectiveness to the first quarter of 2016.

Kings Beach Generation
The CalPeco Electric System has a local-area emergency backup generation facility at Kings Beach (the "King Beach Facility") in Placer County, California. The facility consists of six 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.

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 is addressed by an annual filing.

PPA
During 2015, the Corporation entered into a new multi-year Services Agreement with NV Energy commencing January 2016. The PPA obligates NV Energy to use commercially reasonable efforts to supply the CalPeco Electric System with sufficient renewable power to, combined with the solar project described below, satisfy the current California Renewables Portfolio Standard requirement for the five-year term of the PPA.

The CalPeco Electric System filed an Application with the CPUC in Q2 2015 for authorization to enter into a multi-year Services Agreement with NV Energy commencing January 2016 and authority to recover the costs it will incur under the 2016 NV ESA as energy purchase costs. CPUC approval was received in the fourth quarter of 2015 for the new PPA.

Solar Project
The CalPeco Electric System filed an Application with the CPUC in 2Q15 for the issuance of a Certificate of Public Convenience and Necessity to acquire, own, and operate a solar power generation station with a total generation capacity of up to 60MW (the Solar Project). The application requested authorization for rate recovery of the costs that the CalPeco Electric System will incur to acquire, own, and operate the Solar Project which is owned by Luning Energy, LLC. The application along with the Order issued approving the new PPA with NV Energy allows the CalPeco Electric System to continue procurement of its energy supply in a cost-effective manner for its customers while also allowing the utility to meet its RPS requirements. An order approving the Solar Application (revised to 50MW in a settlement) was issued in December 2015. The project achieved commercial operation in Q1 2017. On January 31, 2017, the Federal Energy Regulatory Commission authorized Luning Energy LLC to make power sales to the CalPeco Electric System pursuant to the 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 44,900 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 38,300 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 18.6% of its total annual sales of approximately U.S. $88.9 million. Its largest customers are a world renowned medical facility and an Ivy League educational institution.

Rate Case

On April 29, 2016, the Granite State Electric System filed a rate application. The application sought a U.S. $5.3 million annual revenue increase proposed for effect July 1, 2016, or a 15.0% increase to distribution revenue, plus an additional U.S. $2.4 million annual increase (step increase) to recover the revenue requirement associated with capital additions made in 2016. The total permanent and step increase being proposed is U.S. $7.7 million annually, or a 21.8% increase to distribution revenue. In June 2016, approval of a temporary rate increase of U.S. $2.4 million was issued, effective July 1, 2016. The final permanent revenue increase will be retroactive to the temporary rate effective date. The step increase would become effective at the time permanent rates become effective following the close of the proceeding. A final order is expected in the second quarter of 2017.

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.

(3) Empire District Electric System (as of January 1, 2017)

Empire operates its businesses as three segments: electric, gas and other. Empire is a public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. As part of its electric segment, it provides water service to three towns in Missouri. The Empire District Gas Company is a wholly owned subsidiary engaged in the distribution of natural gas in Missouri. The other segments consists of a fiber optics business:

<table>
<thead>
<tr>
<th>Electric segment sales*</th>
<th>92.9%</th>
</tr>
</thead>
<tbody>
<tr>
<td>On-system revenues</td>
<td>86.6%</td>
</tr>
<tr>
<td>SPP IM revenues</td>
<td>4.0</td>
</tr>
<tr>
<td>Other revenues</td>
<td>2.0</td>
</tr>
<tr>
<td>Gas segment sales</td>
<td>6.0</td>
</tr>
<tr>
<td>Other segment sales</td>
<td>1.1</td>
</tr>
</tbody>
</table>

*Sales from the electric segment include 0.3% from the sale of water.

The utility portions of the business are subject to regulation by the MPSC, the KCC, the OCC, the APSC and the FERC.

Connection Base

The electric operations serve approximately 170,000 customers as of December 31, 2016, and the 2016 electric operating revenues were derived as follows:
<table>
<thead>
<tr>
<th>Customer Class</th>
<th>% of revenue</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>41.8%</td>
</tr>
<tr>
<td>Commercial</td>
<td>30.4</td>
</tr>
<tr>
<td>Industrial</td>
<td>15.2</td>
</tr>
<tr>
<td>Wholesale on-system</td>
<td>3.5</td>
</tr>
<tr>
<td>Wholesale off-system</td>
<td>4.3</td>
</tr>
<tr>
<td>Miscellaneous sources, primarily public authorities</td>
<td>2.7</td>
</tr>
<tr>
<td>Other electric revenues</td>
<td>2.1</td>
</tr>
</tbody>
</table>

The retail electric revenues for 2016 by jurisdiction were as follows:

<table>
<thead>
<tr>
<th>Jurisdiction</th>
<th>% of revenue</th>
</tr>
</thead>
<tbody>
<tr>
<td>Missouri</td>
<td>90.1 %</td>
</tr>
<tr>
<td>Kansas</td>
<td>4.4</td>
</tr>
<tr>
<td>Oklahoma</td>
<td>2.6</td>
</tr>
<tr>
<td>Arkansas</td>
<td>2.9</td>
</tr>
</tbody>
</table>

**Rate Case Matters**

2015 Rate Case: On October 16, 2015, Empire filed a request with the MPSC for changes in rates for its Missouri electric customers, seeking an annual increase in total revenue of approximately $33.4 million, or approximately 7.3%. On June 21, 2016, Empire announced that it had filed a Unanimous Stipulation and Agreement (the "Empire Rate Case Agreement") with the MPSC. The MPSC issued an order approving the Empire Rate Case Agreement on August 10, 2016 with rates effective September 14, 2016. The Empire Rate Case Agreement allows an annual increase in base revenues of approximately $20.4 million, or 4.46%. Base revenues established by the agreement are lower than the originally requested level of $33.4 million due primarily to lower fuel and purchased power costs than those built into current customer rates. The offsetting effect of reduced revenues and reduced fuel costs results in little impact to gross margin. The most significant factor driving the rate request was the cost associated with the conversion of the Riverton Unit 12 natural gas combustion turbine to combined cycle operation. The Empire Rate Case Agreement calls for the Fuel Adjustment Charge to remain in effect. In addition, a tracking mechanism for non-labor operating and maintenance expenses for the Riverton 12 Combined Cycle Unit will continue and tracking of pension and other post-employment benefit expenses will continue.

**2015 Solar Rebate Tariff**

On May 5, 2015, Empire filed a proposed solar rebate tariff with the MPSC and requested expedited treatment. On May 6, 2015, the MPSC granted Empire's request for expedited treatment of the tariff filing and approved the tariff, effective May 16, 2015. The law provides a number of methods that may be utilized to recover the associated expenses. It is expected that any costs will be recoverable in rates.

**Integrated Resource Plan and Missouri Energy Efficiency Investment Act**

Empire filed its most recent Integrated Resource Plan (IRP) with the MPSC on April 1, 2016. The IRP analysis of future loads and resources is normally conducted once every three years.

**Kansas**

On January 11, 2017, Empire filed a request to implement a rider, the Asbury Environmental and Riverton Rider (AERR), in place of the Asbury Environmental Rider (AER) currently in effect in its Kansas jurisdiction. If approved the new rider will provide a mechanism to begin recovering costs related to the $168 million combined cycle generating unit at the Riverton Power Plant, resulting in an increase in annual revenues of $1.87 million. The KCC will conduct a review of the filing prior to implementation of the new rider. The new rider is expected to take effect no later than 210 days from the date of filing.

**2015 Ad Valorem Tax Surcharge**

On January 22, 2015, Empire filed an Application with the KCC requesting approval of an Ad Valorem Tax Surcharge ("AVTS"). The request sought approval for an annual increase of $0.27 million related to increases in Ad Valorem taxes which exceed amounts currently included in base rates. On February 19, 2015, the KCC approved the request. The new rate was effective February 23, 2015. On January 21, 2016, Empire filed an Application with the KCC requesting approval for a revision to the AVTS. The request sought approval for an annual increase of an additional $0.2 million related to increases in Ad Valorem taxes which exceed amounts currently included in Empire's AVTS rider. This is an annual filing.

**2014 Environmental Cost Recovery Rider**

On December 5, 2014, Empire filed an Application with the KCC requesting approval of the proposed Asbury Environmental Cost Recovery ("AECR") tariff rider. The request sought approval for recovery of the jurisdictional portion of annual carrying
costs (rate of return, income taxes, and depreciation) of approximately $0.86 million, associated with investment in the Asbury AQCS. A Commission Order was received April 15, 2015 approving the rider in the amount of $0.78 million effective June 1, 2015.

**Oklahoma**

On December 21, 2016, Empire filed a request with the OCC for changes in rates for its Oklahoma electric customers, seeking an increase in annual revenues of approximately $3.8 million, or approximately 27.58%. Primary drivers for this case include the $112 million Air Quality Control System (AQCS) at the Asbury Power Plant, the $168 million combined cycle generating unit at the Riverton Power Plant; upgrades to financial, asset, and work management software systems; and other reliability and system improvements to serve customers.

**Arkansas**

**2016 Cost Recovery Rider**

On July 21, 2016, Empire filed a request with the Arkansas Public Service Commission to implement a cost recovery rider for the conversion of the existing Riverton Unit 12 to combined cycle operation. The rider request was approved on October 25, 2016 and Empire began collecting approximately $0.6 million of additional annual revenue on November 1, 2016.

**Municipal Franchise Taxes**

Municipal franchise taxes are collected for and remitted to their respective entities and are included in operating revenues and other taxes in the Consolidated Statements of Income. Municipal franchise taxes of $11.1 million, $11.4 million and $11.8 million were recorded for each of the years ended December 31, 2016, 2015 and 2014, respectively.

**Fuel and Purchased Power**

Fuel and purchased power costs are recorded at the time the fuel is used, or the power purchased. SPP Integrated Marketplace purchased power is also included in fuel and purchased power costs. The net effects of Empire's SPP Integrated Marketplace activity, including SPP Integrated Marketplace net revenue and net purchased power costs, flow through the fuel recovery mechanisms in each state.

In Missouri, the MPSC establishes a base cost for the recovery of fuel and purchased power expenses used to supply energy for the fuel adjustment clause (FAC). Beginning with a 2015 rate order, certain transmission costs are also included in the base cost. The FAC permits the distribution to customers of 95% of the changes in fuel and purchased power costs prudently incurred above or below the base cost. Rates related to the fuel adjustment clause are modified twice a year subject to the review and approval by the MPSC. In accordance with the ASC guidance for regulated operations, 95% of the difference between the actual costs of fuel and purchased power and the base cost of fuel and purchased power recovered from customers is recorded as an adjustment to fuel and purchased power expense with a corresponding regulatory asset or regulatory liability. If the actual fuel and purchased power costs are higher or lower than the base fuel and purchased power costs billed to customers, 95% of these amounts will be recovered from or refunded to customers when the fuel adjustment clause is modified.

In the Kansas jurisdiction, the costs of fuel are recovered from customers through a fuel adjustment clause, based upon estimated fuel costs and purchased power. The adjustments are subject to audit and final determination by regulators. The difference between the costs of fuel used and the cost of fuel recovered from Kansas customers is recorded as a regulatory asset or a regulatory liability if the actual costs are higher or lower than the costs billed to customers, in accordance with the ASC guidance for regulated operations.

Similar fuel recovery mechanisms are in place for Empire's Oklahoma, Arkansas and FERC jurisdictions.

**Derivatives**

Empire utilizes derivatives to help manage its natural gas commodity market risk resulting from purchasing natural gas, to be used as fuel in our electric business or sold in our natural gas business, or on the spot market. Empire also acquires Transmission Congestion Rights (TCR) in an attempt to mitigate congestion costs associated with the power purchased from the SPP Integrated Marketplace.

Pursuant to the ASC guidance on accounting for derivative instruments and hedging activities, derivatives are required to be recognized on the balance sheet at their fair value. On the date a derivative contract is entered into, the derivative is designated as (1) a hedge of a forecasted transaction or of the variability of cash flows to be received or paid related to a recognized asset or liability (“cash-flow” hedge); or (2) an instrument that is held for non-hedging purposes (a “non-hedging” instrument). Empire records the mark-to-market gains or losses on derivatives used to hedge fuel and congestion costs as regulatory assets or liabilities. This is in accordance with the ASC guidance on regulated operations, given that those regulatory assets and liabilities are probable of recovery through the fuel adjustment mechanism.

Empire also enters into fixed-price forward physical contracts for the purchase of natural gas, coal and purchased power. These contracts, if they meet the definition of a derivative, are not subject to derivative accounting because they are considered
to be normal purchase normal sales (NPNS) transactions. If these transactions do not qualify for NPNS treatment, they would be marked to market for each reporting period through regulatory assets or liabilities.

**Fuel, Materials and Supplies**

Fuel, materials and supplies consist primarily of coal, natural gas in storage and materials and supplies, which are reported at average cost.

**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 Corporation 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 Corporation 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 Corporation 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 Corporation’s 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, steam, water and sewer utilities as defined in applicable legislation for issues such as rates, quality of service, finance, accounting, and safety.

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 clause (“PGA”).

(2) **Illinois**

The Corporation’s Illinois operations are regulated by the Illinois Commerce 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 PGA.

(3) **Iowa**

The Corporation’s Iowa operations are regulated by the Iowa Utilities Board.

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 PGA.
(4) Missouri
The Corporation's Missouri utility 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 PGA.

(5) Georgia
The Corporation's Georgia operations are regulated by the Georgia Public Service Commission ("GPSC"). 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 PGA.

(6) Massachusetts
The Corporation'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. 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 PGA.

(iii) Material Facilities

(1) EnergyNorth Gas System
The EnergyNorth Gas System is a regulated natural gas utility providing natural gas distribution services to approximately 90,100 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 81,000 connections, while the commercial and industrial customer base represents approximately 9,100 connections. The commercial and industrial customer base is a diversified mix of retail, medical, educational and industrial uses. No one connection represents more than 3% of its connection base. The EnergyNorth Gas System's largest 10 connections represent approximately 3.0% of its total annual sales of approximately U.S. $106.6 million. Its largest customers are a technology company and multiple public works facilities.

Rate Case
On August 1, 2014, the EnergyNorth 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 consisted of U.S. $13.4 million of permanent base distribution rates and a step increase of U.S. $2.7 million for investments made during a pro forma period. The application included a revenue decoupling proposal and sought recovery of capital costs related to the conversion of the system to the Corporation's ownership. 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. On June 26, 2015, an Order was issued approving a settlement agreement allowing for a U.S. $12.4 million revenue increase effective July 1, 2015.

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.

Growth Projects
The EnergyNorth System in New Hampshire recently filed two applications with the New Hampshire Public Utilities Commission to obtain the franchise rights to provide gas to new territories. One was filed in November 2016 seeking approval to obtain the franchise rights to the Town of Hanover and City of Lebanon. This docket is expected to conclude in 2017. Another application was filed in August 2015 seeking the franchise rights to the towns of Pelham and Windham, which has been approved by the NHPUC.
Midstates Gas System

The Midstates Gas System owns regulated natural gas utilities providing natural gas distribution services to approximately 82,900 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, Kirkville, 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 22,600 connections in Illinois, 4,400 connections in Iowa and 55,900 connections in Missouri with a mix of residential, commercial, industrial and transportation customers. Of the 82,900 connections, approximately 73,300 (88%) are residential connections, while 9,700 (12%) 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 6.1% of its total annual sales of approximately U.S. $63.8 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.

Derivatives

Financial hedges for the natural gas business are recorded at fair value on the balance sheet. Because the Midstates Gas System has a commission approved natural gas cost recovery mechanism (PGA), it records the mark-to-market gain/loss on natural gas financial hedges each reporting period to a regulatory asset/liability account. The regulatory asset/liability account tracks the difference between revenues billed to customers for natural gas costs and actual natural gas expense which is true up at the end of August each year and included in the Actual Cost Adjustment (ACA) factor to be billed to customers during the next year. This is consistent with the ASC guidance on regulated operations, in that the Corporation will be recovering its costs after the annual true up period (subject to a prudence review by the MPSC).

Pursuant to the provisions of the PGA, the difference between actual costs incurred and costs recovered through the application of the PGA (including costs, cost reductions and carrying costs associated with the use of financial instruments) are reflected as a regulatory asset or liability.

Rate Case

On March 31, 2014, the Illinois Gas System filed a rate case with the ICC seeking an increase in revenue of U.S. $5.7 million. The filing was based on a test year that includes anticipated capital expenditures within 2014 and 2015. The case has concluded and an order was issued on February 11, 2015, approving a U.S. $4.6 million revenue increase effective February 20, 2015.

On July 25, 2016, the Illinois Gas System filed a rate application. The application sought a U.S. $3.0 million annual revenue increase to a proposed revenue requirement of U.S. $15.3 million, or a 24% increase, based on a 2017 projected test year. Proposals include a 10.3% ROE, 54% equity, 4.83% cost of debt, 7.8% WACC, and a U.S. $45.0 million rate base. On February 17, 2017, a settlement was filed which calls for an annual revenue increase of $2.3 million, the establishment of a decoupling mechanism, a bad debt tracking mechanism, and a mechanism to enable further system expansion. A final order is expected in May 2017. Its previous rate case was filed in March 2014 and was based on a 2015 projected test year.

On July 25, 2016, the Iowa Gas System filed a rate application. The application seeks a U.S. $1.1 million annual revenue increase to a proposed revenue requirement of U.S. $3.2 million, or a 46% increase, based on a 2015 historical test year with pro-forma changes to June 2016. Proposals include a 10.25% ROE, 54% equity, 4.8% cost of debt, 7.76% WACC, and a U.S. $6.5 million rate base. Interim rates became effective August 4, 2016, allowing an interim revenue increase of U.S. $0.5 million on an annualized basis, or 50% of total proposed increase. On February 17, 2017, a settlement was filed which calls for an annual revenue increase of U.S. $1.0 million. A final order is expected in May 2017. The previous rate case took place in 2001.
(3) Empire District Gas System (as of January 1, 2017)

The Empire District Gas Company (EDG) is a wholly owned subsidiary of the Empire engaged in the distribution of natural gas in Missouri.

Customer Base

The Empire District Gas System serve approximately 43,000 customers as of December 31, 2016, and its 2016 gas operating revenues were derived as follows:

<table>
<thead>
<tr>
<th>Customer Class</th>
<th>% of revenue</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>63.0%</td>
</tr>
<tr>
<td>Commercial</td>
<td>24.6</td>
</tr>
<tr>
<td>Industrial</td>
<td>0.7</td>
</tr>
<tr>
<td>Transportation</td>
<td>9.9</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>1.8</td>
</tr>
</tbody>
</table>

Energy Cost Adjustment Clause

Fuel expense for Empire's gas segment is recognized when the natural gas is delivered to customers, based on the current cost recovery allowed in rates. A PGA allows EDG to recover from its customers, subject to audit and final determination by regulators, the cost of purchased gas supplies and related carrying costs associated with EDG's use of natural gas financial instruments to hedge the purchase price of natural gas. This PGA allows EDG to make rate changes periodically (up to four times) throughout the year in response to weather conditions and supply demands, rather than in one possibly extreme change per year.

(4) Peach State Gas System

The Peach State Gas System is a regulated natural gas system providing natural gas distribution services to approximately 64,500 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 60,200 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 10.2% of its total annual sales of approximately U.S. $68.6 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, 2015, the Peach State Gas System filed an application for an increase in revenue of U.S. $3.4 million in its annual GRAM filing with the Georgia Public Service Commission. New rates were to be effective February 1, 2016, for the period February 1, 2016, through January 31, 2017 to reflect changes in revenue levels and cost of service. The GRAM uses a 12 month base period ending June 2015 (historic test year), with adjustments for the 12 months ending September 2016 (forward looking test year). Commission approval was received in February 2016, allowing for a U.S. $2.7 million rate increase effective March 1, 2016. The difference from the original proposed amount was due to tax depreciation rates and the use of revised inflationary factors applied to operating expenses.

On October 1, 2016, the Peach State Gas System filed its annual GRAM. The application sought a U.S. $0.6 million annual revenue increase to a proposed revenue requirement of U.S. $31.3 million, or a 1.9% increase, based on test year ending...
June 2016. The GRAM proposals included a 10.5% ROE, 55.0% equity, and a U.S. $99.0 million rate base. PSC approval was received Q1 2017, allowing a U.S. $0.7 million increase, with implementation of new rates in February 2017.

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 projects associated with the program are due to be completed in 2017, and the associated rate base under this program will be rolled into the annual GRAM filing in 2018.

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 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.

(5) New England Gas System

The New England Gas System is a regulated natural gas utility providing natural gas distribution services to approximately 54,700 customers in six communities located in the southeastern portion of Massachusetts. The New England Gas System’s distribution network consists of 609 miles of distribution main and 35,660 service lines. The New England Gas System receives gas at five delivery points or gate stations along the Algonquin Gas Transmission Corporation (Spectra Energy) transmission system (not affiliated with APUC).

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 51,000 connections, while the commercial and industrial customer base represents approximately 3,700 connections. New England Gas System’s distribution network consists of 609 miles of distribution main and 35,660 service lines. The New England Gas System’s largest 10 connections represent approximately 4.6% of its total annual sales of approximately U.S. $48.8 million. Its largest customers are waste management and textile companies.

Rate Case

On July 16, 2015, the New England Gas System filed an application with the MDPU seeking an increase in revenue of U.S. $11.8 million, or 14.6%, based on a test year ending December 31, 2014, adjusted for known and measurable changes in calendar 2015. This application represented the first rate case under the Liberty Utilities Group’s ownership. It sought an increase in its general rates for increasing capital costs associated with maintaining the infrastructure and increases in operating and maintenance expenses. The increase reflected a requested return on equity of 10.4% and a debt/equity structure of 45%/55%. An all-party settlement was achieved and filed in December 2015. The settlement included a two-step revenue increase totaling $8.3 million, premised upon a 9.6% return on equity on 50% of capital. A $7.8 million revenue increase was effective March 1, 2016, and a further $0.5 million revenue increase was effective March 1, 2017, contingent upon specified employee additions. On February 10, 2016, an order was issued approving the settlement agreement.

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 more than 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 million, bearing an interest rate of 9.44%, maturing February 15, 2020; U.S. $7.0 million, bearing an interest rate of 7.99%, maturing September 15, 2026; and U.S. $6.0 million, bearing an interest rate of 7.24%, maturing December 15, 2027. The notes have interest only payments, payable semi-annually in arrears.

Natural Gas and Electric 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 shipment and capacity information is available on their public Electronic Bulletin Boards or public websites.

Electric Transmission service is subject to Open Access Transmission Tariffs ("OATT"). With the Empire Acquisition, as of January 1, 2017 APUC acquired transmission facilities in SPP.

The Empire transmission facilities are located within a four state area of Missouri, Kansas, Oklahoma, and Arkansas and Empire is a member of the SPP. The transmission facilities range in voltage from 69 kV up to 345 kV and are offered for service under an OATT approved by the FERC and administered by SPP. Service requests are placed in the SPP Open Access Same-Time Information System (OASIS) and is evaluated by SPP for available capacity. SPP determines who is offered available transmission capacity subject to the SPP Tariff and SPP Market Rules and is offered on a non-discriminatory basis. Service requests can be either point-to-point or network service, where network service is used for serving electric load.

(ii) Principal Markets & Regulatory Environments

Interstate natural gas pipeline transmission assets are regulated primarily by the FERC under the Natural Gas Act. Under this framework, this agency authorizes and certifies all construction, and or abandonment of interstate gas pipeline facilities, requires certificate holders, once operational, to establish and maintain an OATT 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.

Empire's electric transmission operates in the SPP Market and is a member of SPP. The SPP Market covers approximately 550,000 square miles from the Canadian border in Montana and North Dakota in the north to parts of New Mexico, Texas and Louisiana in the south. Southwest Power Pool and its diverse group of member companies coordinate the flow of electricity across 60,000 miles of high-voltage transmission lines spanning 14 states. Empire District Electric is subject to four different states regulatory bodies, SPP Regional Entity (SPP RE) for NERC compliance, SPP Market Rules, and the FERC.

(iii) Material Facilities

Empire District Electric facilities consist of more than 1,200 miles of facilities that qualify as transmission and range in voltage from 69 kV to 345 kV. The majority of the Empire District transmission is 161 kV. The transmission facilities consist of terminal equipment, transformers, lines, towers, and associated equipment consistent with owning and operating a high voltage transmission system.

3.2.3 Specialized Skill and Knowledge

The Liberty Utilities 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 Liberty Utilities Group will typically retain the existing employees with such specialized skill and knowledge.

In addition, the Liberty Utilities 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 Liberty Utilities Group’s businesses have geographic monopolies in their service territories and are therefore insulated from competition. The Liberty Utilities 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 Liberty Utilities 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.

The Corporation 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, the Central Basin and Apple Valley facilities in California, a weather normalization adjustment is applied to customer bills that adjust 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.

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 U.S. $4.5 million or U.S. $53.4 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.

The Empire Electric System experiences peak loads in both the winter and summer seasons, due to heating and cooling loads associated with weather in its service territory. The competitive market for power supply is managed by the Southwest Power Pool. The Default Service price for power may fluctuate as a result of the weather, but those costs are passed through directly to customers and as a result does not have a material financial impact.

(iii) Natural Gas Systems

The Liberty Utilities 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 Corporation 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 Liberty Utilities Group operates have approved mechanisms to mitigate demand fluctuations.

3.2.6 Customers

The Liberty Utilities Group's businesses derive their revenues from a diverse residential, commercial and industrial customer base. For the twelve months ended December 31, 2016, electricity sales and distribution were approximately 50% from residential customers and 50% from commercial and industrial customers; natural gas sales and distribution were approximately 50% from residential customers and 50% from commercial and industrial customers; and water and waste water sales were approximately 69% from residential customers and 31% from commercial and industrial customers.

The EnergyNorth Gas 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 rates with 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.
3.3 Related Party Transactions

(i) Emera Inc.
A member of the Board of APUC is an executive at Emera. During 2016, the Energy Services Business sold electricity to Maine Public Service Company, and Bangor Hydro subsidiaries of Emera, amounting to U.S. $10.2 million as compared to U.S. $6.7 million during the same period in 2015. During 2016, Liberty Utilities purchased natural gas amounting to U.S. $3.9 million as compared to U.S. $2.3 million during the same period in 2015 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. On May 13, 2016, a subsidiary of the Corporation and Emera Utility Services Inc. entered into a design, engineering, supply and construction agreement for the Tinker transmission upgrade project. The total cost of the contract is estimated at $8.8 million and is expected to be completed in 2017. The contract followed a market based request for proposal process. On October 14, 2016, APUC paid $0.7 million to Emera as reimbursement for professional services incurred and accrued in 2014.

There was U.S. $0.8 million included in accruals in 2016 as compared to U.S. $0.5 million during the same period in 2015, related to these transactions at the end of the year.

(ii) Equity-method investments
The Corporation provides administrative services to its equity-method investees and is reimbursed for incurred costs. To that effect, the Corporation charged its equity-method investees $3.3 million as compared to $2.0 million during the same period in 2015.

(iii) Trafalgar
The Corporation owned 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 entity partially and indirectly owned by Senior Executives (the "Related Entity"), moved to foreclose on the assets on behalf of the Corporation. Subsequent to the foreclosure action, Trafalgar went into bankruptcy. APUC and the Related Entity commenced joint pursuit of litigation and bankruptcy proceedings with Trafalgar in 2002.

In 2003 and 2004, the Corporation reimbursed the Related Entity $1.0 million of the approximately $2.0 million in third-party legal fees it had initially funded and APUC agreed to fund future legal fees and other liabilities. It was agreed that any net proceeds from the litigation and bankruptcy proceedings would be shared proportionally to the quantum of net legal costs funded by each party.

On June 30, 2016, the Corporation received U.S. $10.1 million in proceeds from the settlement of this matter and, the third quarter, paid U.S. $2.9 million to the Related Entity as its proportionate share. The gain to APUC, net of legal and other liabilities, of approximately U.S. $6.6 million was recorded in the second quarter of 2016.

(iv) Long Sault Hydro Facility
Effective December 31, 2013, APUC acquired the shares of Algonquin Power Corporation Inc. ("APC") which was partially owned by Senior Executives. APC owns the partnership interest in the 18MW Long Sault Hydro Facility. A final post-closing adjustment related to the transaction is expected to be settled in 2017.

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

3.4 Principal Revenue Sources

As at March 10, 2017, APUC owned, directly or indirectly interests in thirty-seven renewable generation facilities and four thermal generation facilities including those identified in "Corporate Structure – Intercorporate Relationships – Other Interests in Energy Related Developments", three electrical distribution utilities, seven natural gas distribution utilities, 1 propane gas distribution utility, and 23 water distribution and wastewater utilities.

For the year ended December 31, 2016, APUC derived approximately 22.2% of its revenues from its interests in power generation facilities (21.7% in 2015), 20.8% of its revenues from electrical distribution utilities (21.8% in 2015), 37.0% of its revenues from natural gas distribution utilities (45.2% in 2015), and 16.6% of its revenues from its interests in water distribution and wastewater utilities (7.6% in 2015).

The purchase of electricity and natural gas by the Corporation'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 Corporation 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 27.6% of its revenues from its interests in power generation facilities (29.9% in 2015), 13.5% of its revenues from electrical distribution utilities (14.2%
in 2015), 33.0% of its revenues from natural gas distribution utilities (38.0% in 2015), and 21.2% of its revenues from its interests in water distribution and wastewater utilities (12.1% in 2015).

3.5 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, 2016. 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 Enterprise 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.

3.6 Employees
APUC's Executive Management Group consists of nine individuals including the Presidents of the Renewable Generation Group and the Liberty Utilities Group. As at December 31, 2016, APUC employed 1,490 people.

The Renewable Generation Group employs a total of 150 employees. All of the employees of the Renewable Generation Group are non-unionized.

The Liberty Utilities Group employs a total of 1,200 employees. The Liberty Utilities Group employees are non-unionized with the exception of: 60 employees at the CalPeco Electric System, 43 employees at the Midstates Gas System, 183 employees at the EnergyNorth Gas and Granite State Electric System, and 80 employees at the New England Gas System.

The Corporate and shared services groups consist of an additional 140 employees located at the APUC corporate offices in Oakville, Ontario.

With the closing of the Empire Acquisition, the Liberty Utilities Group added 735 employees, of which 357 are unionized.

3.7 Foreign Operations
For the twelve months ended December 31, 2016, approximately 84% of EBITDA and 83% of cash flow are generated from operations located in the United States and are denominated in U.S. Dollars.

3.8 Economic Dependence
The largest customer on a percentage basis is PJM, which totalled 2.9% of gross revenues in the year ended December 31, 2016. Receivables from PJM are invoiced monthly and generally collected within 14 days. The second largest customer on a percentage basis is Manitoba Hydro which totalled 2.6% of gross revenues in the year ended December 31, 2016. Receivables are invoiced monthly and generally collected within 20 days. The third largest customer is Quebec Hydro, totaling 2.5% of gross revenues in the year ended December 31, 2016. Receivables are invoiced monthly and generally collected within 21 days.

Details on the credit ratings of the above customers can be found in “Risk Factors – Credit-Counterparty”.

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.
3.9 Social or Environmental Policies

APUC has formal policies and procedures that support its commitment to corporate responsibility ("CR"). APUC's Code of Business Conduct and Ethics is the foundation of the Corporation's CR 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 an annual online test 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 business. 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 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 Corporation'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.

3.10 Credit Ratings

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

<table>
<thead>
<tr>
<th></th>
<th>S&amp;P</th>
<th>DBRS</th>
<th>Moody's</th>
</tr>
</thead>
<tbody>
<tr>
<td>APUC - Issuer rating</td>
<td>BBB</td>
<td>BBB</td>
<td>BBB(low)</td>
</tr>
<tr>
<td>APUC - Preferred Shares</td>
<td>P-3 ³</td>
<td>P-3 ³</td>
<td>Pfkd-3 (low)</td>
</tr>
<tr>
<td>APCo - Issuer rating</td>
<td>BBB</td>
<td>BBB</td>
<td>BBB (low)</td>
</tr>
<tr>
<td>APCo - Senior unsecured debt</td>
<td>BBB</td>
<td>BBB</td>
<td>BBB (low)</td>
</tr>
<tr>
<td>Liberty Utilities</td>
<td>BBB</td>
<td>BBB</td>
<td>-</td>
</tr>
<tr>
<td>LU GP1 - Issuer rating²</td>
<td>-</td>
<td>-</td>
<td>BBB (high)</td>
</tr>
<tr>
<td>LU GP1 - Senior unsecured notes</td>
<td>-</td>
<td>-</td>
<td>BBB (high)</td>
</tr>
<tr>
<td>Empire - Issuer rating</td>
<td>BBB</td>
<td>BBB</td>
<td>-</td>
</tr>
<tr>
<td>Empire - First mortgage bonds</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Empire - Senior unsecured debt</td>
<td>-</td>
<td>-</td>
<td>Baa1</td>
</tr>
<tr>
<td>Empire - Commercial paper</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

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.
Financial, Risks

liquidity, reporting, risk

As identifies, An Short-term 1, rating the Moody's conditions, and "(high)" addition conditions "BBB" are "(low)" designation 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.

DBRS

DBRS Limited ("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. A rating of "BBB" by DBRS denotes an obligor having 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.

Moody's

Moody's Investors Service, Inc. ("Moody's") rates debt instruments and issuers with ratings ranging from "Aaa", which represent the greatest ability of an obligor to meet its financial commitment, to "C", which represents an obligor in payment default. A rating of "A" by Moody's denotes obligations judged to be upper-medium grade and are subject to low credit risk, while a rating of "Baa" by Moody's denotes an obligations judged to be medium-grade and subject to moderate credit risk and as such may possess certain speculative characteristics. A Moody's rating may be modified by the addition of a numerical modifiers 1, 2, and 3 to show relative standing within the major rating categories.

Short-term obligations of an issuer may carry a rating ranging from Prime-1 or "P-1", which represents an issuer's superior ability to repay short-term debt obligations, to "P-3", which represent an issuer's acceptable ability to repay short-term obligations.

4. ENTERPRISE RISK FACTORS

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. Risk information is sourced throughout the organization using a variety of methods including risk identification interviews and workshops, as well as APUC's "Risk Insights" program, which provides all employees with a mechanism to communicate risks and opportunities at any time. Key risks and associated mitigation strategies are reviewed by the executive-level Enterprise Risk Management Council and are presented to the Board of Directors Corporate Governance, Risk and Compensation Committee on a quarterly basis. The key risk categories assessed include: safety, environment, natural disasters, compliance, security (physical and cyber), financial reporting, 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 scoring matrix to assess impact and likelihood. Financial, reputation, and safety implications are among those 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 and business plans.

The development and execution of risk treatment plans for the organization’s top risks are actively monitored by the Executive team. 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 reported to the Board audit committee on a quarterly basis. All material changes to exposures, controls or treatment plans of key risks are reported to the ERM team, Enterprise Risk Management Council, and the Board of Directors Corporate Governance, Risk and Compensation Committee 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.

4.1 Treasury Risk Factors

4.1.1 Downgrade in the Corporation's Credit Rating Risk

APUC has a long term consolidated corporate credit rating of BBB (flat) from S&P and a BBB (low) rating from DBRS. APCo has a BBB (low) issuer rating from DBRS. Liberty Utilities Finance GP1, a special purpose financing entity of Liberty Utilities Co has a BBB (high) issuer rating from DBRS. Empire has a BBB rating from S&P and a Baal rating from Moody's.

The ratings indicate the agencies’ assessment of APUC’s ability to pay the interest and principal of debt securities it issues. A rating is not a recommendation to purchase, sell or hold securities and each rating should be evaluated independently of any other rating. The lower the rating, the higher the interest cost of the securities when they are sold. A downgrade in APUC’s or its subsidiaries issuer corporate credit ratings would result in an increase in APUC’s borrowing costs under its bank credit facilities and future long term debt securities issued. If any of APUC’s ratings fall below investment grade (investment grade is defined as BBB- or above for S&P and BBB low or above for DBRS), APUC’s ability to issue short-term debt or other securities or to market those securities would be impaired or made more difficult or expensive. Therefore, any such downgrades could have a material adverse effect on APUC’s business, cost of capital, financial condition and results of operations.

No assurances can be provided that any of APUC’s current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant.

4.1.2 Liquidity Risk

As of December 31, 2016, the Corporation had approximately $3,913.4 million of consolidated indebtedness. Management of the Corporation believes, based on its current expectations as to the Corporation’s future performance, that the cash flow from its operations and funds available to it under its revolving credit facilities and its ability to access capital markets will be adequate to enable the Corporation to finance its operations, execute its business strategy and maintain an adequate level of liquidity. However, expected revenue and the costs of planned capital expenditures are only estimates. Moreover, actual cash flows from operations are dependent on regulatory, market and other conditions that are beyond the control of the Corporation. As such, no assurance can be given that management’s expectations as to future performance will be realized.

The ability of the Corporation to raise additional debt or equity or to do so on favorable terms may be affected by the Corporation’s financial and operational performance, and by financial market disruptions or other factors outside the control of the Corporation.

In addition, the Corporation may at times incur indebtedness in excess of its long-term leverage targets, in advance of raising the additional equity necessary to repay such indebtedness and maintain its long-term leverage target. Any increase in the degree of the Corporation’s leverage could, among other things, limit the Corporation’s ability to obtain additional financing for working capital, investment in subsidiaries, capital expenditures, debt service requirements, acquisitions and general corporate or other purposes; restrict the Corporation’s flexibility and discretion to operate its business; limit the Corporation’s ability to declare dividends on its Common Shares; require the Corporation to dedicate a portion of cash flows from operations to the payment of interest on its existing indebtedness, in which case such cash flows will not be available for other purposes; cause ratings agencies to re-evaluate or downgrade the Corporation’s existing credit ratings; expose the Corporation to increased interest expense on borrowings at variable rates; limit the Corporation’s ability to adjust to changing market conditions; place the Corporation at a competitive disadvantage compared to its competitors that have less debt; make the Corporation vulnerable to any downturn in general economic conditions; and render the Corporation unable to make expenditures that are important to its future growth strategies.

The Corporation will need to refinance or reimburse amounts outstanding under the Corporation’s existing consolidated indebtedness over time. There can be no assurance that any indebtedness of the Corporation will be refinanced or that additional financing on commercially reasonable terms will be obtained, if at all. In the event that such indebtedness cannot be refinanced, or if it can be refinanced on terms that are less favorable than the current terms, the ability of the Corporation to declare dividends may be adversely affected.
The ability of the Corporation to meet its debt service requirements will depend on its ability to generate cash in the future, which depends on many factors, including the financial performance of the Corporation, debt service obligations, the realization of the anticipated benefits of acquisition and investment activities, and working capital and future capital expenditure requirements. In addition, the ability of the Corporation to borrow funds in the future to make payments on outstanding debt will depend on the satisfaction of covenants in existing credit agreements and other agreements. A failure to comply with any covenants or obligations under the Corporation’s consolidated indebtedness could result in a default under one or more such instruments, which, if not cured or waived, could result in the termination of dividends by the Corporation and permit acceleration of the relevant indebtedness. If such indebtedness were to be accelerated, there can be no assurance that the assets of the Corporation would be sufficient to repay such indebtedness in full. There can also be no assurance that the Corporation will generate cash flow in amounts sufficient to pay outstanding indebtedness or to fund any other liquidity needs.

4.1.3 Tax Risk and Uncertainty

APUC is subject to income and other taxes primarily in the United States and Canada. Changes in tax laws or interpretations thereof in the jurisdictions in which we do business could adversely affect APUC’s results from operations, our return to shareholders, and cash flow. The Corporation endeavors to take tax positions that are sustainable, however, there can be no assurance that the tax positions taken by the Corporation will not be subject to challenge by the Canada Revenue Agency (‘CRA’) or the IRS. A successful challenge by either agency could impact our return to shareholders.

There is the potential for changes to the U.S. tax code (Internal Revenue Code or "IRC"). It is not possible to know what change to the IRC, if any, will be enacted in the U.S., and therefore, it is not possible to know what effect the changes, if any, might have on the Corporation. There can be no assurance that any changes to the U.S. IRC would not impact the Corporation’s tax-related assets, liabilities, and expense which could materially adversely affect the Corporation’s business, financial condition, results of operations and prospects.

Development by the Renewable Generation Group of renewable power generation facilities in the United States is dependent in part on federal tax credits and other tax incentives, the availability of which requires that construction of the applicable facility be commenced by a statutory deadline. While these incentives have been extended on multiple occasions, the most recent extension provides for a multi-year step-down in the amount of the incentives. There can be no assurance that reduced incentive levels will be sufficient to support continued development and construction of renewable power facilities in the United States, nor that the applicable legislation will not be further limited. In addition, the Renewable Generation Group has entered into certain tax equity financing transactions with financial partners for certain of its renewable power facilities in the United States, under which allocations of future cash flows to the Corporation from the applicable facility could be adversely affected in the event that there are changes in U.S. tax laws that apply to facilities previously placed in service.

4.1.4 Credit/Counterparty Risk

APUC and its subsidiaries through its long term power purchase contracts, trade receivables, derivative financial instruments and short term investments are subject to credit risk with respect to the ability of customers and other counterparties to perform their obligations to the Corporation.

Approximately 94% of the Renewable 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, or BBB or higher by DBRS. The following chart sets out the Renewable Generation Group’s customers representing greater than 5% of total revenues and their credit ratings and percentage of total revenue associated with the customer:

<table>
<thead>
<tr>
<th>Counterparty</th>
<th>Credit Rating</th>
<th>Approximate Annual Revenues</th>
<th>Percent of Revenue</th>
</tr>
</thead>
<tbody>
<tr>
<td>PJM Interconnection LLC</td>
<td>Aa2</td>
<td>$32.2</td>
<td>13.2%</td>
</tr>
<tr>
<td>Ontario Electricity Financial Corporation</td>
<td>Aa2</td>
<td>29.7</td>
<td>12.2%</td>
</tr>
<tr>
<td>Manitoba Hydro</td>
<td>A</td>
<td>28.7</td>
<td>11.8%</td>
</tr>
<tr>
<td>Hydro Quebec</td>
<td>Aa2</td>
<td>27.5</td>
<td>11.3%</td>
</tr>
<tr>
<td>Commonwealth Edison</td>
<td>Baa1</td>
<td>25.0</td>
<td>10.3%</td>
</tr>
<tr>
<td>Pacific Gas and Electric Company</td>
<td>A3</td>
<td>22.6</td>
<td>9.3%</td>
</tr>
<tr>
<td>Electric Reliability Council of Texas (ERCOT)</td>
<td>Aa3</td>
<td>17.4</td>
<td>7.2%</td>
</tr>
<tr>
<td>Connecticut Light and Power</td>
<td>Baa1</td>
<td>14.3</td>
<td>5.9%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td>$197.4</td>
<td></td>
</tr>
</tbody>
</table>

1 Ratings by Moody’s, Standard & Poor’s, or DBRS.
The remaining revenue of the Corporation is primarily earned by the Liberty Utilities Group. In this regard, the credit risk attributed to the Liberty Utilities Group’s accounts receivable balances at the water and wastewater distribution systems total U.S. $16.1 million which is spread over approximately 178,000 connections, resulting in an average outstanding balance of approximately $90 dollars per connection.

The natural gas distribution systems' accounts receivable balances related to the natural gas utilities total U.S. $46.8 million, while electric distribution systems accounts receivable balances related to the electric utilities total U.S. $21.1 million. The natural gas and electrical utilities both derive over 86% of their revenue from residential customers.

Adverse conditions in the energy industry or in the general economy, as well as circumstances of individual customers or counterparties, may adversely affect the ability of a customer or counterparty to perform as required under its contract with the Corporation. Losses from a utility customer may not be fully compensated through bad debt reserves approved by the applicable utility regulator. If a customer under a long-term power purchase agreement with the Renewable Generation Group is unable to perform, the Renewable Generation Group may be unable to replace the contract on comparable terms, in which case sales of power (and, if applicable, renewable energy credits and ancillary services) from the facility would be subject to market price risk and may require refinancing of indebtedness related to the facility or otherwise have a material adverse effect. Default by other counterparties, including counterparties to hedging contracts that are in an asset position and to short-term investments, also could adversely affect the financial results of the Corporation.

4.1.5 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 84% of EBITDA in 2016 and 83% 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 $40.0 million ($0.16 per share) on an annual basis. In light of the currency profile of its operations, APUC pays its dividend in U.S. dollars. APUC further manages currency risk through the matching of U.S. dollar denominated long term debt for the debt requirements of its U.S. operations, thereby creating a natural hedge for the operating profit vis a vis financing costs. Although APUC may enter into derivative contracts to hedge currency exchange rate exposure, the Corporation typically does not hedge its full exposure. To the extent that the Corporation does enter into currency hedges, the Corporation will not realize the full benefits of favorable exchange rate movement, and is subject to risks that the counterparty to the hedging contracts may prove unable or unwilling to perform their obligations under the contracts.

The $1.15 billion of convertible debentures raised in the first quarter of 2016 to fund the acquisition of Empire were denominated in Canadian dollars. In order to mitigate the effects of a potential funding mismatch due to fluctuations in the foreign exchange rate, over the course of 2016 the Corporation converted the total expected proceeds into U.S. dollars by purchasing spot and forward currency exchange contracts with an average U.S. exchange rate of approximately $1.3282. Hedge accounting was not applicable, hence changes in value of the forward contracts have been recorded in the Corporation’s Statement of Operations.

4.1.6 Market Price Risk

The Renewable 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 Renewable 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 Corporation 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 Corporation to purchase power in the merchant market. To mitigate the risk of production shortfalls under hedges, the Renewable 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 grid curtailments or mechanical failures, production shortfalls may be such that the Renewable Generation Group may still be forced to purchase power in the merchant market at prevailing rates to settle against a hedge.

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

On May 15, 2012, the Renewable Generation Group entered into a financial hedge, which expired December 31, 2016, with respect to its Dickson Dam Hydro Facility located in the Western region. The financial hedge was structured to hedge 75% of the facility’s expected production volume against exposure to the Alberta Power Pool’s current spot market rates. Starting in 2017, the unhedged production based on long term projected averages is approximately 65,000 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. $0.7 million on an annualized basis.
The July 1, 2012 acquisition of the Sandy Ridge Wind Facility included a financial hedge, which commenced on January 1, 2013, for a 10 year period. The financial hedge is structured to hedge 72% of the Sandy Ridge Wind Facility’s 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 price would result in a change in revenue of approximately U.S. $0.4 million for the year.

The December 10, 2012 acquisition of the Senate Wind Facility included a physical hedge, which commenced on January 1, 2013, for a 15 year period. The physical hedge is structured to hedge 64% of the Senate Wind Facility’s 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 price would result in a change in revenue of approximately U.S. $2.0 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 approximately U.S. $2.0 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 could be material but 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 Renewable 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, 2016, the Renewable Generation Group had not entered into any such short-term derivative contracts.

The January 1, 2013 acquisition of the Shady Oaks Wind Facility included a power sales contract, which commenced on June 1, 2012 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 approximately U.S. $0.5 million for the year.

4.1.7 Commodity Price Risk

The Renewable Generation Group’s exposure to commodity prices is primarily limited to exposure to natural gas price risk. The Liberty Utilities Group is exposed to energy and natural gas price risks at its electric and natural gas 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 164,000 MW-hrs in fiscal 2017, of which 133,000 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 25,000 MW-hrs of its energy requirements at the ISO-NE spot rates to supplement self-generated energy should the Maritime region be able to reach the estimated 164,000 MW-hrs. The cost associated with the expected market purchases of 25,000 MW-hrs is mitigated through the use of short-term financial energy hedge contracts which cover approximately 78% of the Maritime region's anticipated purchases during the price-volatile winter months at an average rate of approximately $83 per MW-hr. For the amount of anticipated purchases not covered by hedge contracts, each U.S. $10.00 change per MW-hr in the market prices in ISO-NE would result in a change in expense of $0.1 million on an annualized basis.

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 energy cost adjustment clause (“ECAC”) mechanism, which allows for the recovery or refund of changes in energy costs that are caused by the fluctuations in the price of fuel and purchased power. On a monthly basis, energy costs are compared to the CPUC approved base tariff energy rates and the difference is deferred to a balancing account. Annually,
based on the balance of the ECAC balancing account, if the ECAC revenues were to increase or decrease by more than 5%, the CalPeco Electric System's ECAC tariff allows for a potential adjustment to the ECAC rates which would eliminate the risk associated with the fluctuating cost of fuel and purchased power. 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(s) take on the risk associated with fluctuating customer usage and commodity prices. The supplier is paid for the commodity by the Granite State Electric System which in turns receives pass-through rate recovery through a formal filing and approval process with the New Hampshire Public Utilities Commission ("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 Least Cost Integrated Resource Plan filing. In addition, EnergyNorth Natural Gas System files with the NHPUC for recovery of its transportation and commodity costs on a semi-annual basis through the Cost of Gas ("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 a 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 corresponding COG filing, i.e. winter to winter and summer to summer.

The Midstates Gas Systems purchases pipeline capacity, storage and commodity from a variety of counterparties, and files with the three individual State Commissions for recovery of its transportation and commodity costs through an annual Purchase Gas Adjustment ("PGA") filing and approval process. The 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, the Corporation has implemented a commodity hedging program designed to hedge approximately 25-50% of its non-storage related commodity purchases. All gains and losses associated with the hedging program are allowed to be a 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.

The Georgia (Peach State) Gas System purchases pipeline capacity, storage and commodity from a variety of counterparties, and files with the Georgia PSC for recovery of its transportation, storage and commodity costs through a monthly PGA filing process. The Peach State Gas System establishes rates for its customers within the PGA filings and these rates are designed to fully recover its anticipated transportation, storage and commodity costs. In order to minimize commodity price fluctuations, the annual Gas Supply Plan filed by the Corporation and approved by the PSC includes a commodity hedging program designed to hedge approximately 30% of its non-storage related commodity purchases during the winter months. All gains and losses associated with the hedging program are passed through to customers in the PGA filings and are embedded in the approved rates in such filings. Rates can be adjusted on a monthly basis in order to account for any differences in gas costs relative to the amounts assumed in the PGA filings, minimizing any under or over collection of its gas costs.

Empire has a fuel cost recovery mechanism in all of its jurisdictions, as such impacts on net income exposure to commodity cost fluctuations are significantly reduced. However, cash flow could still be impacted by any increased expenditures. Empire met approximately 54% of its 2016 generation fuel supply need through coal. Approximately 97% of its 2016 coal supply was Western coal. Empire has contracts and binding proposals to supply a portion of the fuel for its coal plants through 2018. These contracts satisfy approximately 92% of anticipated fuel requirements for 2017 and 23% for 2018 for the Asbury Coal Facility. In order to manage exposure to fuel prices, future coal supplies will be acquired using a combination of short-term and long-term contracts.

Empire is exposed to changes in market prices for natural gas needed to run combustion turbine generators. Empire's natural gas procurement program is designed to manage costs to avoid volatile natural gas prices. Empire periodically enters into physical forward and financial derivative contracts with counterparties to meet future natural gas requirements by locking in
prices (with respect to predetermined percentages of our expected future natural gas needs) in an attempt to lessen the volatility in fuel expenditures and improve predictability. Gains and losses associated with the hedging program are passed through to customers in the fuel accommodation clause and PGA filings and are embedded in the approved rates in such filings.

4.1.8 Defined Benefit Pension Plan Risk

In conjunction with certain utilities acquisitions, the Corporation assumed defined benefit pension and OPEB plans for qualifying employees in the related acquired businesses. The legacy plans of the electricity, gas and water utilities are non-contributory defined pension plans covering all eligible legacy and union employees of the acquired businesses. Benefits are generally based on each employee's years of service and compensation. The Corporation also provides a defined benefit cash balance pension plan covering new employees, transitioned employees and certain legacy employees under which employees are credited with a percentage of base pay plus a prescribed interest rate credit. The OPEB plans provide health care and, in some cases, 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 engages professional investment managers to manage the investments 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.

4.1.9 Substantial Indebtedness Relating to the Empire Acquisition

APUC substantially increased its amount of indebtedness following the Empire Acquisition

As part of the Empire Acquisition, APUC assumed all of Empire's existing debt. As a result, APUC substantially increased its amount of indebtedness upon the Empire Acquisition and such increased indebtedness may adversely affect APUC's cash flow and ability to operate its business.

The Empire Acquisition and related financing, including the Offering, could result in a downgrade of the credit rating of APUC, Empire and/or their subsidiaries

The change in the capital structure of APUC as a result of the Empire Acquisition, and the entering into of the Empire Acquisition Credit Facilities could cause credit rating agencies which rate the outstanding debt obligations of APUC to re-evaluate and potentially downgrade the Corporation's current credit ratings, which could increase the Corporation's borrowing costs.

The Empire Acquisition could also result in a downgrade of the credit ratings of Empire and The Empire District Gas Company as well as significant mandatory redemption notices of five outstanding series of bonds if the credit rating of either company, or of APUC as the acquirer, falls below “BB+” or lower by S&P or “Ba1” or lower by Moody’s.

Should such an event occur, Empire must make an offer to purchase all of the outstanding Empire bonds. To the extent that such offer is accepted, the bonds must be purchased at 100% of the principal amount, together with accrued and unpaid interest.

4.1.10 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 and had no amounts outstanding as at December 31, 2016. As a result, a 100 basis point change in the variable rate charged would not impact interest expense;
- The Generation Credit Facility is subject to a variable interest rate and had $242.9 million outstanding as at December 31, 2016. A 100 basis point change in the variable rate charged would impact interest expense by $2.4 million annually;
- The Liberty Credit Facility is subject to a variable interest rate and had no amounts outstanding as at December 31, 2016. As a result, a 100 basis point change in the variable rate charged would not impact interest expense;
- The Acquisition Facility is subject to a variable interest rate and had $1,794.4 million (U.S. $1,336.4 million) outstanding as at December 31, 2016. A 100 basis point change in the variable rate charged would impact interest expense by $17.9 million annually;
- The Corporate Term Facility is subject to a variable interest rate and had $315.5 million (U.S. $235.0 million) outstanding as at December 31, 2016. A 100 basis point change in the variable rate charged would impact interest expense by $3.2 million annually;
• The Park Water System term credit facility is subject to a variable interest rate and had $30.2 million (U.S. $22.5 million) outstanding as at December 31, 2016. A 100 basis point change in the variable rate charged would impact interest expense by $0.3 million annually; and

• To mitigate financing risk, from time to time APUC may seek to fix interest rates on expected future financings.
  • In the fourth quarter of 2014, the Renewable 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 applies to this transaction. Consequently, changes in fair value, to the extent deemed effective, are being recorded in Other Comprehensive Income.
  • On October 25, 2016, the Corporation entered into forward contracts to purchase U.S. $250.0 million 10-year U.S. Treasury bills at an interest rate of 1.8395% and U.S. $250.0 million 30-year U.S. Treasury bills at an interest rate of 2.5539% settling on February 13, 2017 in order to reduce the interest rate risk related to the probable issuance on that date of U.S. $500.0 million bonds in relation to the acquisition of Empire (note 3(a)). Subsequent to year-end, the Corporation entered into a note purchase agreement to issue U.S. $750 million of notes with a weighted average coupon of 4.0% based on pricing established on January 27, 2017 (note 9(c)). Concurrent with the pricing of the notes, the Corporation also settled the open forward contracts on January 27, 2017, resulting in an effective interest rate on the bond offering of approximately 3.6%. Hedge accounting will apply to the effective portion of the realized gain on the hedge, while the ineffective portion of approximately U.S. $0.6 million will be recorded in income in the first quarter of 2017.

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.

4.2 Operational Risk Factors

4.2.1 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.

The Renewable Generation Group’s hydro assets utilize dams to pond water for generation and if the dam fail, 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 programs to reduce the likelihood of dam failure.

The Renewable Generation Group’s wind assets could 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 Original Equipment Manufacturers (‘OEMs’), which provide for regular inspections and maintenance of property and liability insurance policies. Exposures related to blade icing can be mitigated by shutting down the units as icing is detected.

The Renewable 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 reduce output of the facility. The mechanical and operational risks at the thermal facilities 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 Renewable Generation Group’s electric generating stations are subject to mechanical breakdown. The risk of mechanical breakdown is mitigated by properly maintaining the units and by regular inspections.

The Liberty Utilities 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 Liberty Utilities Group’s electric distribution systems are subject to 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 Liberty Utilities 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 and geographically, the use of regular maintenance programs, including pipeline safety programs and compliance programs, maintaining adequate insurance and an active Enterprise Risk Management program.

4.2.2 Development and Construction Risk

The Corporation actively engages in the development and construction of new power generation facilities. 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 Corporation’s overall performance. There are risks that actual costs may exceed budget estimates, delays may occur in obtaining permits and materials, suppliers and contractors may not perform as required under their contracts, there may be inadequate availability, productivity or increased cost of qualified craft labor, start-up activities may take longer than planned, the scope and timing of projects may change, and other events beyond the Corporation's control may occur that may materially affect the schedule, budget, cost and performance of projects. Regulatory approvals can be challenged by a number of mechanisms which vary across state and provincial jurisdictions. Such permitting challenges could identify issues that may result in permits being modified or revoked.

The Corporation mitigates these risk through its due diligence processes, sound project management practices, formal risk management processes and appropriate contingency plans.

*Risks specific to Renewable Generation Projects:*

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 Corporation 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.

4.2.3 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 Energy Efficiency Risk

Regulatory and legislative bodies have proposed requirements and incentives to increase energy efficiency and reduce energy consumption. In addition, significant technological advancements are taking place in the electric industry, including advancements related to self-generation and distributed energy technologies such as fuel cells, micro turbines, wind turbines and solar cells. Adoption of these technologies may increase as a result of government subsidies.

Increased adoption of these practices, requirements and technologies could reduce demand for utility-scale electricity generation, which may adversely affect market prices at which the Renewable Generation Group can sell wholesale electric power.

Increased adoption of these practices would not materially decrease the operating costs and capital expenditure requirements for the Liberty Utilities Group’s electric distribution systems but, in the case of self-generation, may decrease the pool of customers from whom fixed costs would be recovered. If the Liberty Utilities Group were unable to adjust its electric distribution rates to reflect the reduced electricity demand, the Corporation’s business, financial condition and results of operations could be adversely affected.

4.2.5 Cyber Security

APUC relies upon information technology networks and systems to process, transmit and store electronic information, and to manage or support a variety of business processes and activities, including the generation, transmission and distribution of electricity, supply chain functions, and the invoicing and collection of payments from the Corporation’s customers. APUC also use information technology systems to record, process and summarize financial information and results of operations for internal reporting purposes and to comply with financial reporting, legal and tax requirements. APUC’s technology networks and systems collect and store sensitive data including system operating information, proprietary business information belonging to APUC and third parties, and personal information belonging to the Corporation’s customers and employees.
APUC’s information technology networks and infrastructure may be vulnerable to damage, disruptions or shutdowns due to attacks by hackers or breaches due to employee error or malefeasance, or other disruptions during software or hardware upgrades, telecommunication failures or natural disasters or other catastrophic events. The occurrence of any of these events could impact the reliability of APUC’s generation, transmission and distribution systems; could expose the Corporation, its customers or employees to a risk of loss or misuse of information; and could result in legal claims or proceedings, liability or regulatory penalties against the Corporation, damage its reputation or otherwise harm the business. APUC cannot accurately assess the probability that a security breach may occur, despite the measures that APUC takes to prevent such a breach, and the Corporation is unable to quantify the potential impact of such an event. APUC can provide no assurance that the Corporation or any of its subsidiaries will identify and remedy all security or system vulnerabilities or that unauthorized access or error will be identified and remedied.

Additionally, APUC cannot predict the impact that any future information technology or terrorist attack may have on the energy industry in general. APUC’s facilities could be direct targets or indirect casualties of such attacks. The effects of such attacks could include disruption to APUC’s generation, transmission and distribution systems or to the electrical grid in general, and could increase the cost of insurance coverage or result in a decline in the U.S. or Canadian economies.

4.2.6 Environmental Risks

The Corporation is subject to extensive federal, state, provincial and local regulation with regard to air and other environmental matters. Failure to comply with these laws and regulations could have a material adverse effect on the Corporation’s results of operations and financial position. In addition, new environmental laws and regulations, and new interpretations of existing environmental laws and regulations, have been adopted and may in the future be adopted which may substantially increase the Corporation’s future environmental expenditures for both new and existing facilities. Although the Liberty Utilities Group historically has recovered such costs through regulated customer rates, there can be no assurance that the Liberty Utilities Group will recover all or any part of such increased costs in future rate cases. The Renewable Generation Group generally has no right to recover such costs from customers. The incurrence of additional material environmental costs which are not recovered in utility rates may result in a material adverse effect on the Corporation’s business, financial condition and results of operations.

The Corporation 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. Certain environmental risks associated with the Corporation’s operations include uncontrolled natural gas or contaminant releases (or releases above the permitted limits), failure to maintain compliance with obligations under permits and licenses (such as continuous emissions monitoring, periodic reporting/source testing, and general performance/operating conditions), operations adjustments resulting from wildlife mortality monitoring, and dam safety.

In addition, like other industrial companies, the Corporation’s operating subsidiaries generate certain hazardous wastes which must be managed in accordance with various federal, state and local environmental laws. Under federal and state Superfund laws, potential liability for historic contamination of property may be imposed on responsible parties jointly and severally, without fault, even if the activities were lawful when they occurred. In the case of the Liberty Utilities Group, these costs are often allowed in rate case proceedings to be recovered from customers over a specified period.

4.2.7 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 ability to quantify such expense, the timing of incurring the potential expenses, as well as other factors which may be considered in evaluating if such obligations exist and in estimating the fair value of such obligations.

The Liberty Utilities Group’s facilities are operated with the assumption that their services will be required in perpetuity and there are no contractual decommissioning requirements. In order to remain in compliance with the applicable regulatory bodies, the Liberty Utilities Group has regular programs at each facility to ensure its equipment is properly maintained and replaced on a cyclical basis. These costs can generally be included in the facility’s rate base and thus the Liberty Utilities Group expects to be allowed to earn a return on such investment.

In conjunction with acquisitions and developed projects, the Corporation assumed certain asset retirement obligations. The asset retirement obligations mainly relate to legal requirements for: (i) removal of wind facilities upon termination of land leases; (ii) cut (disconnect from the distribution system), purge (clean of natural gas and PCB contaminants), and cap gas mains within the gas distribution and transmission system when mains are retired in place, or dispose of sections of gas main when removed from the pipeline system; (iii) clean and remove storage tanks containing waste oil and other waste contaminants; and (iv) remove asbestos upon major renovation or demolition of structures and facilities.
4.2.8 Dependence Upon Key Customers

A substantial portion of the output of the Renewable Generation Groups power generation facilities is sold under long-term power purchase agreements, under which a single purchaser is obligated to purchase all of the output of the applicable facility and (in most cases) associated renewable energy credits. The termination of any such power purchase agreement, unless replaced on equally favorable terms, would increase the Corporation’s exposure to wholesale power market price risk, which could have an adverse effect on the business, financial condition and results of operations of the Corporation.

4.2.9 Personnel and Labour

The Corporation’s operations depend on the continued efforts of its employees. Retaining key employees and maintaining the ability to attract new employees are important to the Corporation’s operational and financial performance. The Corporation cannot guarantee that any member of its management or any one of its key employees will continue to serve in any capacity for any particular period of time.

Certain events, such as an aging workforce, mismatch of skill set or complement to future needs, or unavailability of contract resources may lead to operating challenges and increased costs. The challenges the Corporation might face as a result of such risks include a lack of resources, losses to its knowledge base and the time required to develop new workers’ skills. In any such case, costs, including costs for contractors to replace employees, productivity costs and safety costs may rise. If the Corporation is unable to successfully attract and retain an appropriately qualified workforce, its financial position or results of operations could be negatively affected.

While labor relations have been stable to date and there have not been any disruptions in operations as a result of labor disputes with employees, the maintenance of a productive and efficient labor environment without disruptions cannot be assured. In the event of a strike, work stoppage or other form of labor disruption, the Corporation would be responsible for procuring replacement labor and could experience disruptions in its utility operations.

4.2.10 Obligations to Serve

The Liberty Utilities 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 Liberty Utilities Group may be required to solicit additional capital or obtain additional borrowings to finance these future construction obligations.

4.2.8 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.

4.3 Regulatory Climate and Permitting Risks

4.3.1 Regulatory Climates

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

The Liberty Utilities Group’s facilities are subject to rate setting by state regulatory agencies. The time between the occurrence 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. In order to mitigate this exposure, the Liberty Utilities Group seeks to obtain approval for regulatory constructs in the states in which it operates to allow for timely recovery of operating expenses. 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 may need to find other efficiencies or cost savings to achieve its allowed returns.

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

4.3.2 Health and Safety Laws

The operation of the Corporation’s facilities requires adherence to safety standards imposed by regulatory bodies. These laws and regulations require the Corporation to obtain approvals and maintain permits, undergo environmental impact assessments and review processes and implement environmental, health and safety programs and procedures to control risks associated with the citing, construction, operation and decommissioning of wind energy projects. Failure to operate the facilities in strict compliance with these regulatory standards may expose the facilities to claims and administrative sanctions.
Health and safety laws, regulations and permit requirements may change or become more stringent. Any such changes could require us to incur materially higher costs than the Corporation has incurred to date. The Corporation’s costs of complying with current and future health and safety laws, regulations and permit requirements, and any liabilities, fines or other sanctions resulting from violations of them, could adversely affect its business, financial condition and results of operations.
4.3 Condemnation Expropriation Proceedings

The Liberty Utilities Group’s water, wastewater, 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 that just and fair compensation be paid to the Liberty Utilities Group, and the Liberty Utilities Group believes that such compensation generally would reflect fair market value for any assets that are taken. However, the determination of such fair and just compensation will be undertaken pursuant to a legal proceeding and, therefore, there is no assurance as to the value that would be received for those assets, including that the value received would be above book value or that the Corporation would not recognize a loss.

4.4 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. Acquisition risks also include delays in implementation, failure to realize operating benefits or synergies from completed transactions, assumption or incurrence of unexpected costs or liabilities, negative impacts on liquidity or credit ratings, and failure to retain key personnel, among others.

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 has developed standard project management and governance processes to manage its respective company integrations due to acquisitions. These processes promote the 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 senior management of the Renewable Generation Group and the Liberty Utilities Group 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 Renewable Generation Group and the Liberty Utilities Group.

4.4.1 Failure to Realize Intended Benefits

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 the Corporation’s business or service offerings, and that expected operating benefits or synergies from completed transactions will not be realized. In addition, the Corporation may incur unexpected costs or liabilities in connection with any acquisition.

The success of an acquisition may depend on retention of the workforce or key employees of the acquired business. Although in such cases the Corporation undertakes efforts to retain employees of the acquired business and includes the estimated cost of retention in its decision-making with respect to the acquisition, the accuracy of such estimates and success of such efforts cannot be assured.

The Corporation seeks to avoid unexpected liabilities through the conduct of its due diligence investigation of the target business and through contractual remedies for material misrepresentations in the acquisition agreement. However, detailed information regarding the target business is generally available only from the seller, and contractual remedies are typically subject to negotiated limitations. In addition, in cases in which the target company is publicly traded and its shares are widely held, the Corporation is likely not to have recourse following the completion of the acquisition for misrepresentations made to the Corporation in connection with the acquisition. There may be liabilities of the target that the Corporation failed to discover or was unable to quantify in the due diligence conducted prior to closing an acquisition. The discovery or quantification of any material liabilities of a target could have a material adverse effect on the Corporation’s business, financial condition, results of operations or future prospects, as the Corporation may partially or fully bear the risk for any inaccuracies in the information, representations or warranties provided by an acquired target entity.

4.4.2 Integration Risks

Although management believes that post-closing an acquisition of the Corporation will provide benefits to the Corporation, there is a risk that some or all of the expected benefits of the acquisition may fail to materialize, or may not occur within the time periods anticipated by the Corporation. The realization of such benefits may be affected by a number of factors, many of which are beyond the control of the Corporation. The challenge of combining previously independent businesses makes evaluating the Corporation’s business and future financial prospects difficult. The past financial performance of the Corporation may not be indicative of its future financial performance.

Failure to realize the anticipated benefits of an acquisition may impact the financial performance of the Corporation, the price of its Common Shares and the ability of APUC to continue to pay dividends on its Common Shares at current rates or
at all. The declaration of dividends by the Corporation is at the discretion of the Board and the Board may determine at any time to cease paying dividends.

4.4.3 Demands on Management and Operating Systems

The pursuit and completion of acquisitions place significant demands on the Corporation’s managerial, operational and financial personnel and systems. No assurance can be given that the Corporation’s systems, procedures and controls will be adequate to support the expansion of the Corporation’s operations resulting from completed acquisitions. The Corporation’s future operating results will be affected by the ability of its officers and key employees to manage changing business conditions and to implement and improve effective operational and financial controls and reporting systems.

4.4.4 Divesting at a Loss

The Corporation may from time to time dispose of businesses or assets that the Corporation no longer views as being strategic to the Corporation’s continuing operations. Although the Corporation seeks to maximize the price obtained for any such business or assets, the Corporation may recognize a loss upon such a sale. In addition, divestitures may result in a reduction in total revenues and net income.

5. DIVIDENDS

Common Shares

The total amount of dividends declared on the Common Shares for fiscal 2014, 2015, and 2016 were $82.9 million, $124.8 million, and $149.2 million respectively. The amount of dividends declared for each Common Share of APUC for fiscal 2014, 2015 and 2016 were $0.37, $0.49, and $0.55 respectively.

APUC follows a quarterly dividend schedule, subject to subsequent Board declarations each quarter. On January 16, 2017, the Board approved a dividend increase of U.S. $0.0424 per common share annually, bringing the total annual dividend to U.S. $0.4659 per common share, an increase of 10% over the previous annual dividend rate.

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 “Enterprise Risk Factors”.

Preferred Shares

On November 9, 2012, APUC issued 4,800,000 Series A Shares (the “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 each of 2014, 2015 and 2016, dividends paid to Series A Shareholders totalled $5.4 million per year.

On January 1, 2013, the Corporation issued 100 redeemable Series C 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 Shares provide dividends essentially identical to that expected from the Class B units. In 2014, 2015 and 2016, dividends paid to Series C preferred shareholders were $0.9 million, $0.9 million and $0.9 million, respectively.

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, 2015, and 2016, dividends paid to Series D Shareholders totalled $4.1 million, $5.0 million and $5.0 million, respectively.

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, 2016, 61,419,484 Common Shares had been registered with the Reinvestment Plan.

6. DESCRIPTION OF CAPITAL STRUCTURE

6.1 Common Shares

The Common Shares are publicly traded on the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE"). During the fourth quarter APUC received approval to list its common shares for trading on the NYSE under the ticker symbol "AQN". The Corporation has been a U.S. Securities and Exchange Commission ("SEC") registrant since 2009 and operates primarily in the United States. APUC shares continue to be listed on the TSX also under the ticker symbol "AQN".

As at December 31, 2016, APUC had 274,087,018 issued and outstanding Common Shares.

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

6.2 Private Placements of Subscription Receipts and Common Shares to Emera

Until 2016, Emera was the largest shareholder of APUC. In 2016, Emera disposed of 100% of its interests in APUC with a sale on May 24, 2016 of 50,126,766 Common Shares and a sale on December 8, 2016 of 12,938,457 Common Shares. Consequently, as at March 10, 2017, Emera owns no Common Shares. The strategic investment agreement with Emera was terminated on January 13, 2017.

Common Shares

For the year ended December 31, 2016, APUC issued a total of 12,938,457 Common Shares for proceeds of $110.5 million pursuant to the conversion of subscription receipts issued to Emera in contemplation of certain previously announced transactions, as outlined below:

- On December 29, 2014, the Corporation received total proceeds of $77.5 million from the issuance to Emera of 8,708,170 subscription receipts at a price of $8.90 per share in connection with the Odell SponsorCo investment. Effective June 30, 2016, Emera converted the subscription receipts for no additional consideration on a one-for-one basis into common shares and received 661,693 additional common shares in lieu of dividends declared during the holding period.

- On December 29, 2014, the Corporation received total proceeds of $33.0 million from the issuance to Emera of 3,316,583 subscription receipts at a price of $9.95 per share in connection with the Park Water System acquisition. Effective June 30, 2016, Emera converted the subscription receipts for no additional consideration on a one-for-one basis into common shares and received 252,011 additional common shares in lieu of dividends declared during the holding period.

For the year ended December 31, 2015, APUC did not issue any Common Shares to Emera.

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

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. As at December 31, 2016, APUC had outstanding:

- 4,800,000 cumulative rate reset Series A Shares, yielding 4.5% annually for the initial six-year period ending on December 31, 2018;

- 100 Series C preferred shares that were issued in exchange for 100 Class B limited partnership units by St. Leon; and

- 4,000,000 cumulative rate reset Series D Shares, yielding 5.0% annually for the initial five-year period ending on March 31, 2019.
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 Portfolio 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 Shares to the holders of the Class B units of St. Leon LP, in exchange for such Class B 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, 2016, 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 Convertible Unsecured Subordinated Debentures

On February 9, 2016, in connection with the acquisition of Empire, the Corporation completed the sale of $1.0 billion aggregate principal amount of 5.0% convertible unsecured subordinated debentures. The Debentures were sold on an instalment basis at a price of $1,000 per Debenture, of which $333 dollars was paid on closing of the Debenture Offering with the remaining $667 dollars (the “Final Installment”) payable on a date (the “Final Installment Date”) fixed following satisfaction of conditions precedent to the closing of the acquisition of Empire. On March 9, 2016, the underwriters exercised their option to acquire an additional $150.0 million of Debentures bringing the total Debentures issued under the Debenture Offering to $1.15 billion.

The Debentures will mature on March 31, 2026. The Debentures accrued interest at an annual rate of 5% per $1,000 dollars principal amount of Debentures until and including the Final Installment Date, after which the interest rate became 0%.

At the option of the holders and provided that payment of the Final Installment has been made, each Debenture is convertible into Common Shares of the Corporation at any time prior to the earlier of maturity or redemption by the Corporation, at a conversion price of $10.60 per Common Share.

The Final Installment Date took place on February 2, 2017. The proceeds received from the Final Installment was $767.1 million before financing costs of $23.0 million. Holders of the Debentures who paid the Final Installment by February 2, 2017 received, in addition to the payment of accrued and unpaid interest, a make-whole payment, representing the interest that would have accrued from the day following the Final Installment Date up to and including March 1, 2017. Based on the first instalment of $333 per $1,000 principal amount of the Debentures and the make-whole payment, the effective annual yield to and including the Final Installment Date was 16.4%.

APUC will issue up to 108,490,566 common shares on conversion of all of the Debentures. As at March 1, 2017, a total of 107,517,895 common shares of the company were issued, representing conversion into common shares of more than 99.1% of the Debentures. Debentures not converted may be redeemed by the Corporation at a price equal to their principal amount plus any unpaid interest, which accrued prior to and including the Final Installment Date. At maturity, the Corporation will have the right to pay the principal amount due in cash or in common shares. In the case of common shares, such shares will be valued at 95% of their weighted average trading price on the TSX for the 20 consecutive trading days ending five trading days preceding the maturity date.

6.5 Employee Share Purchase Plan

APUC has an Employee Share Purchase Plan (the “ESPP”) which allows eligible employees to use a portion of their earnings to purchase Common Shares. 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. Common shares purchased through the company match portion shall not be eligible for sale by the participant for a period of one year following the contribution date on which such shares were acquired. At 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. During the year, the Corporation issued 144,264 Common Shares to employees under the ESPP plan.

As at December 31, 2016, a total of 496,030 shares had been issued under the ESPP.

6.6 Directors Deferred Share Units

APUC has a deferred share unit plan. Under the plan, non-employee directors of APUC may elect annually to receive all or any portion of their compensation in deferred share units (“DSUs”) in lieu of cash compensation. Up to 1,000,000 common shares may be issued from treasury under the plan. 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 Corporation’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 APUC. As APUC does not expect to settle the DSU’s in cash, these DSUs are accounted for as equity awards.

During the twelve months ended December 31, 2016, the Corporation issued 67,192 DSUs to the directors of the Corporation.

As at December 31, 2016, a total of 224,663 DSUs had been granted under the DSU plan.
6.7 Performance Share Units

APUC issues performance share units ("PSUs") to its employees as part of APUC's long-term incentive program. PSUs are granted annually for three-year overlapping performance cycles. PSUs vest at the end of the three-year cycle based on established performance criteria. At the end of the three-year performance periods, the number of common shares issued can range from 0% to 197.5% of the number of PSUs granted. Dividends accumulating during the vesting period are converted to PSUs based on the market value of the shares on that date and are recorded in equity as the dividends are declared. None of these PSUs have voting rights. Any PSUs not vested at the end of a performance period will expire.

The plan provides for settlement in cash or shares at the election of the Corporation. 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 Corporation 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 ratably over the performance period based on APUC’s estimated achievement of the established metrics. Compensation expense for awards with performance conditions will only be recognized for those awards for which it is probable that the performance conditions will be achieved and which are expected to vest. The compensation expense will be estimated based upon an assessment of the probability that the performance metrics will be achieved and anticipated vesting percentage.

During the twelve months ended December 31, 2016, the Corporation granted (including dividends) 219,315 PSUs to executives and employees of the Corporation. During the year the Corporation settled 181,875 PSU by issuing 91,280 shares from treasury, with the balance withheld as payment in lieu of minimum tax withholdings.

As at December 31, 2016, a total of 578,988 PSUs are 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 (the "Amended and Restated Rights Plan") was approved by shareholders at the annual and special meeting of shareholders of APUC held in 2016.

Until the occurrence of certain specific events, the rights will trade with the Common Shares and be represented by certificates representing the Common Shares. The rights become exercisable only when a person, including any party related to it or acting jointly with it (subject to certain exceptions), 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 105 days. If at the end of 105 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 June 9, 2016, the shareholders of APUC approved an amendment to and the continuance of the Rights Plan. The amendments to the Rights Plan included:

- amending the definition of Permitted Bid to be outstanding for a minimum period of 105 days or such shorter period that a take-over bid must remain open for deposits of securities, in the applicable circumstances, pursuant to Canadian securities laws; and
- certain additional non-substantive, technical and administrative amendments, including to align the definition of a Competing Permitted Bid to the minimum number of days as required under Canadian securities laws.

The Amended and Restated Rights Plan will remain in effect until the termination of the annual meeting of the shareholders of APUC in 2019 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 stock options ("Options"), to acquire a proprietary interest in the Corporation.

The Stock Option Plan authorizes the Board to issue 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 8% of the number of Common Shares outstanding at the time the Options are granted, less the Common Shares issuable under grants under all other securities-based compensation plans. 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 8% 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);

- 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.

In 2016, the shareholders of APUC approved a provision whereby in the event that the Corporation restates its financial results, any unpaid or unexercised options may be cancelled at the discretion of the Board (or the compensation committee of the Board (“Compensation Committee”)) in accordance with the terms of the Corporation’s clawback policy.

During the twelve months ended December 31, 2016, the Corporation granted 2,596,025 options to executives of the Corporation. The options allow for the purchase of common shares at a weighted average price of $10.85, the market price of the underlying common share at the date of grant. In March 2016, executives of the Corporation exercised 3,715,663 stock options at a weighted average exercise price of $5.25 in exchange for 2,720,980 common shares issued from treasury and 994,683 shares withheld as payment in lieu of minimum tax withholdings.

As at December 31, 2016, a total of 6,045,014 options are issued and outstanding under the plan.

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 and NYSE under the symbol “AQN”. The following table sets forth the high and low trading prices and the aggregate volumes of trading of the Common Shares for the periods indicated (as quoted by the TSX and NYSE).

<table>
<thead>
<tr>
<th>2016</th>
<th>TSX</th>
<th>NYSE1</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>High ($)</td>
<td>Low ($)</td>
</tr>
<tr>
<td>January</td>
<td>11.61</td>
<td>10.30</td>
</tr>
<tr>
<td>February</td>
<td>12.01</td>
<td>10.35</td>
</tr>
<tr>
<td>March</td>
<td>11.07</td>
<td>10.30</td>
</tr>
<tr>
<td>April</td>
<td>10.97</td>
<td>10.58</td>
</tr>
<tr>
<td>May</td>
<td>11.68</td>
<td>10.90</td>
</tr>
<tr>
<td>June</td>
<td>12.05</td>
<td>11.46</td>
</tr>
<tr>
<td>July</td>
<td>12.45</td>
<td>11.97</td>
</tr>
<tr>
<td>August</td>
<td>12.31</td>
<td>11.70</td>
</tr>
<tr>
<td>September</td>
<td>12.14</td>
<td>11.65</td>
</tr>
<tr>
<td>October</td>
<td>11.98</td>
<td>11.30</td>
</tr>
<tr>
<td>November</td>
<td>11.89</td>
<td>10.47</td>
</tr>
<tr>
<td>December</td>
<td>11.61</td>
<td>10.88</td>
</tr>
</tbody>
</table>

1. Common shares commenced trading on the NYSE on November 29, 2016

7.1.2 Preferred Shares

Series A Shares

APUC’s Series A Shares became listed and commenced trading on the TSX under the symbol “AQN.PR.A” on November 9, 2012.

The following table sets forth the high and low trading prices and the aggregate volume of trading of the Series A Shares for the periods indicated (as quoted by the TSX).
<table>
<thead>
<tr>
<th>2016</th>
<th>High ($)</th>
<th>Low ($)</th>
<th>Volume</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
<td>17.55</td>
<td>14.10</td>
<td>60,202</td>
</tr>
<tr>
<td>February</td>
<td>15.83</td>
<td>13.42</td>
<td>81,570</td>
</tr>
<tr>
<td>March</td>
<td>15.85</td>
<td>13.79</td>
<td>83,092</td>
</tr>
<tr>
<td>April</td>
<td>16.85</td>
<td>15.30</td>
<td>55,776</td>
</tr>
<tr>
<td>May</td>
<td>16.80</td>
<td>16.32</td>
<td>69,234</td>
</tr>
<tr>
<td>June</td>
<td>17.60</td>
<td>16.16</td>
<td>60,369</td>
</tr>
<tr>
<td>July</td>
<td>17.56</td>
<td>16.23</td>
<td>179,782</td>
</tr>
<tr>
<td>August</td>
<td>18.67</td>
<td>16.90</td>
<td>267,718</td>
</tr>
<tr>
<td>September</td>
<td>18.44</td>
<td>17.53</td>
<td>38,233</td>
</tr>
<tr>
<td>October</td>
<td>19.06</td>
<td>18.12</td>
<td>313,235</td>
</tr>
<tr>
<td>November</td>
<td>19.61</td>
<td>18.32</td>
<td>170,274</td>
</tr>
<tr>
<td>December</td>
<td>20.08</td>
<td>18.59</td>
<td>64,878</td>
</tr>
</tbody>
</table>

Series D Shares

APUC’s Series D Shares became listed and commenced trading on the TSX under the symbol “AQN.PR.D” on March 5, 2014. The following table sets forth the high and low trading prices and the aggregate volume of trading of the Series D Shares for the periods indicated (as quoted by the TSX).

<table>
<thead>
<tr>
<th>2016</th>
<th>High ($)</th>
<th>Low ($)</th>
<th>Volume</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
<td>21.55</td>
<td>17.23</td>
<td>39,157</td>
</tr>
<tr>
<td>February</td>
<td>18.93</td>
<td>15.81</td>
<td>47,574</td>
</tr>
<tr>
<td>March</td>
<td>18.65</td>
<td>16.39</td>
<td>77,698</td>
</tr>
<tr>
<td>April</td>
<td>18.84</td>
<td>17.75</td>
<td>155,681</td>
</tr>
<tr>
<td>May</td>
<td>18.65</td>
<td>17.34</td>
<td>80,505</td>
</tr>
<tr>
<td>June</td>
<td>19.25</td>
<td>17.98</td>
<td>73,990</td>
</tr>
<tr>
<td>July</td>
<td>19.23</td>
<td>18.30</td>
<td>61,300</td>
</tr>
<tr>
<td>August</td>
<td>20.98</td>
<td>19.08</td>
<td>38,941</td>
</tr>
<tr>
<td>September</td>
<td>20.60</td>
<td>19.45</td>
<td>46,192</td>
</tr>
<tr>
<td>October</td>
<td>21.05</td>
<td>20.01</td>
<td>215,192</td>
</tr>
<tr>
<td>November</td>
<td>21.96</td>
<td>20.75</td>
<td>61,883</td>
</tr>
<tr>
<td>December</td>
<td>22.96</td>
<td>21.10</td>
<td>73,492</td>
</tr>
</tbody>
</table>

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, 2014, 2015, and 2017.

On May 19, 2015, 1,608,974 Options were granted to senior executives of APUC and senior managers which allow for the purchase of Common Shares at a price of $9.76 per share. On August 27, 2015, 18,551 Options were granted to senior executives of APUC and senior managers which allow for the purchase of Common Shares at a price of $9.23 per share. One-third of the Options vest on each of January 1, 2016, 2017, and 2018.

On March 31, 2016, 2,487,601 Options were granted to senior executives of APUC which allow for the purchase of Common Shares at a price of $10.82 per share. On June 12th, 2016, 108,424 Options were granted to senior executives of APUC which allow for the purchase of Common Shares at a price of $11.59 per share. One-third of the Options vest on each of January 1, 2017, 2018, and 2019.

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. See the table below for a summary of options granted and exercised during the year ended December 31, 2016 and the balance of options issued and outstanding and exercisable as at December 31, 2016.

<table>
<thead>
<tr>
<th>Balance at December 31, 2015</th>
<th>7,164,652</th>
<th>6.92</th>
<th>4.74</th>
</tr>
</thead>
<tbody>
<tr>
<td>Granted</td>
<td>2,596,025</td>
<td>10.85</td>
<td>8.00</td>
</tr>
<tr>
<td>Exercised</td>
<td>(3,715,663)</td>
<td>5.25</td>
<td>2.06</td>
</tr>
<tr>
<td>Balance at December 31, 2016</td>
<td>6,045,014</td>
<td>9.64</td>
<td>6.27</td>
</tr>
<tr>
<td>Exercisable at December 31, 2016</td>
<td>2,120,539</td>
<td>8.36</td>
<td>5.16</td>
</tr>
</tbody>
</table>

7.3 Escrowed Securities and Securities Subject to Contractual Restrictions on Transfer

There are no securities of APUC that are subject to contractual restrictions on transfer as of the date of this AIF.

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.

<table>
<thead>
<tr>
<th>Name and Place of Residence</th>
<th>Principal Occupation</th>
<th>Served as Director or Officer of APUC from</th>
</tr>
</thead>
<tbody>
<tr>
<td>CHRISTOPHER J. BALL</td>
<td>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.</td>
<td>Director of APUC since October 27, 2009. Trustee of APCo since October 22, 2002</td>
</tr>
<tr>
<td>Name and Place of Residence</td>
<td>Principal Occupation</td>
<td>Served as Director or Officer of APUC from</td>
</tr>
<tr>
<td>-----------------------------</td>
<td>----------------------</td>
<td>------------------------------------------</td>
</tr>
<tr>
<td>LINDA BEAIRSTO Oakville, Ontario, Canada Age: 56</td>
<td>Ms. Beairsto is the Chief Compliance Officer and previously was the Chief General Counsel and Corporate Secretary for APUC from June 2011 to February 6, 2017. Prior to joining APUC, she held various 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., EVP &amp; 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. She was awarded a Chartered Director (C.Dir) designation from McMaster University, DeGroote School of Business as well as a Certified Compliance &amp; Ethics Professional (CCEP)® designation from the Compliance Certification Board.</td>
<td>Officer of APUC since June 6, 2011</td>
</tr>
<tr>
<td>DAVID BRONICHESKI Oakville, Ontario, Canada Age: 57</td>
<td>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.</td>
<td>Officer of APUC since October 27, 2009. Officier of APCo since September 17, 2007</td>
</tr>
<tr>
<td>CHRISTOPHER HUSKILSON Wellington, Nova Scotia, Canada Age: 59</td>
<td>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.</td>
<td>Director of APUC since October 27, 2009. Trustee of APCo since July 27, 2009</td>
</tr>
<tr>
<td>CHRISTOPHER K. JARRATT Oakville, Ontario, Canada Age: 58</td>
<td>Christopher Jarratt has over 25 years of experience in the independent electric power and utility sectors and is Vice Chair of APUC. Mr. Jarratt is a founder and principal of APIC, 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 &amp; Young Entrepreneur of the Year finalist award.</td>
<td>Director of APUC since June 23, 2010.</td>
</tr>
<tr>
<td>D. RANDY LANEY Farmington, Arkansas, USA Age: 62</td>
<td>D. Randy Laney was most recently Chairman of the Board of Empire District Electric Company since 2009. He led the Board of Empire in 2003 serving as the Non-Executive Vice Chairman of the Board from 2008 to 2009 and Non-Executive Chairman of the Board from April 23, 2009 until APUC’s acquisition of Empire on January 1, 2017. Mr. Laney, semi-retired since 2008, has held numerous senior level positions with both public and private companies during his career, including 23 years with Wal-Mart Stores, Inc. in various executive positions including Vice President of Finance, Benefits and Risk Management and Vice President of Finance and Treasurer. In addition, Mr. Laney has provided strategic advisory services to both private and public companies and served on numerous profit and non-profit boards. Mr. Laney brings significant management and capital markets experience, and strategic and operational understanding to his position on the APUC Board.</td>
<td>Director of APUC since February 1, 2017</td>
</tr>
<tr>
<td>KENNETH MOORE Toronto, Ontario, Canada Age: 58</td>
<td>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 &amp; 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. Dr. (Chartered Director).</td>
<td>Director of APUC since October 27, 2009. Trustee of APCo since December 18, 1998</td>
</tr>
<tr>
<td>Name and Place of Residence</td>
<td>Principal Occupation</td>
<td>Served as Director or Officer of APUC from</td>
</tr>
<tr>
<td>-----------------------------</td>
<td>------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
<td>------------------------------------------</td>
</tr>
<tr>
<td><strong>JEFF NORMAN</strong>&lt;br&gt;Burlington, Ontario, Canada&lt;br&gt;Age: 48</td>
<td>Jeff Norman is the Chief Development Officer of the Corporation, serving in this role since 2008. He was appointed to the APUC executive team in 2015. Mr. Norman co-founded the Algonquin Power Venture Fund in 2003 and served as President until it was acquired by Algonquin Power Co. (APCo) in 2008. Since 2008 the business development team has secured over 1GW of commercially secure renewable energy projects. Mr. Norman has over 24 years of experience and has reviewed the economic merits of hundreds of renewable energy projects located throughout North America.</td>
<td>Officer of APUC since May 25, 2015</td>
</tr>
<tr>
<td><strong>DAVID PASIEKA</strong>&lt;br&gt;Oakville, Ontario, Canada&lt;br&gt;Age: 60</td>
<td>David Pasieka is the Chief Operating Officer of APUC’s Liberty Utilities Group. As Chief Operating Officer, 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.</td>
<td>Officer of APUC since September 1, 2011</td>
</tr>
<tr>
<td><strong>IAN E. ROBERTSON</strong>&lt;br&gt;Oakville, Ontario, Canada&lt;br&gt;Age: 57</td>
<td>Ian Robertson is the Chief Executive Officer of the Corporation. Mr. Robertson is a founder and principal of APCI, 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), as well as a Global Professional Master of Laws degree from the University of Toronto 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.</td>
<td>Director of APUC since June 23, 2010.</td>
</tr>
<tr>
<td><strong>MASHEED SAIDI</strong>&lt;br&gt;Dana Point, California, United States&lt;br&gt;Age: 62</td>
<td>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 U.S. Transmission for National Grid USA, for which she was responsible for all aspects of U.S. transmission business. Ms. Saidi previously served as Chairperson of the Board of Directors for the non-profit organization, Mary’s Shelter, and also previously served on the Board of Directors of the Northeast Energy and Commerce Association. 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.).</td>
<td>Director of APUC since June 18, 2014</td>
</tr>
<tr>
<td><strong>DILEK SAMIL</strong>&lt;br&gt;Las Vegas, Nevada, United States&lt;br&gt;Age: 61</td>
<td>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.</td>
<td>Director of APUC since October 1, 2014</td>
</tr>
</tbody>
</table>
MIKE SNOW
Markham, Ontario, Canada
Age: 56
Mike joined APUC in 2011 and serves as Chief Operating Officer of APUC’s Renewable Generation Group. He is responsible for all aspects of strategy, business development, operations, asset management, human resources, and evaluating and reporting on growth and operational activities. Mike 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 Ivey School of Business - Western University. Mike received his Chartered Director designation from McMaster University in 2014 and sits on the Board of Governors of the University of Ontario Institute of Technology.

Director of APUC since
July 4, 2011

MELISSA STAPLETON BARNES
Carmel, Indiana, United States of America
Age: 48
Melissa Stapleton Barnes has been Senior Vice President, Business Risk Management, and Chief Ethics and Compliance Officer for Eli Lilly and Company since January, 2013. Reporting directly to the CEO and Board of Directors, she is an executive officer and serves as a member of the company’s executive committee. She previously held the role of Vice President, Deputy General Counsel from 2012 to 2013; and General Counsel, Lilly Diabetes and Lilly Oncology and Senior Director and Assistant General Counsel from 2010 - 2012. She holds a Bachelor of Science in Political Science & Government (highest distinction) from Purdue University and a Juris Doctorate from Harvard Law School. Ms. Barnes is a member of several professional organizations including Ethisphere - Business Ethics Leadership Alliance; CEB, Corporate Ethics Leadership Council; Conference Board, Global Council on Business Conduct; Healthcare Businesswomen’s Association, and is a Licensed Attorney with the Indiana State Bar. Other board positions include The Center for the Performing Arts (Vice Chair), Visit Indy, The Children’s Museum, and The Great American Songbook.

Director of APUC since
June 9, 2016

GEORGE L. STEEVES
Aurora, Ontario, Canada
Age: 67
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

JENNIFER TINDALE
Campbellville, Ontario, Canada
Age: 45
Jennifer Tindale is the Chief Legal Officer of the Corporation. Ms. Tindale has over 20 years of experience advising public companies on acquisitions, dispositions, mergers, financings, corporate governance and disclosure matters. From July, 2011 to February, 2017, Ms. Tindale was the Executive Vice President, General Counsel & Secretary at a cross-listed real estate investment trust. Prior to that, she was Vice President, Associate General Counsel & Corporate Secretary at a public Canadian-based pharmaceutical company and before that she was a partner at a top tier Toronto law firm, practising corporate securities law. Ms. Tindale holds a Bachelor of Arts and a Bachelor of Laws from the University of Western Ontario.

Officer of APUC since
February 7, 2017

GEORGE TRISIC
Oakville, Ontario, Canada
Age: 56
George Trisic is the Chief Administrative Officer and Corporate Secretary 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. Additionally, he has completed the Chartered Director program of the Directors College (McMaster University) and has the certification of C.Dir (Chartered Director).

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 February 28, 2017, the directors and executive officers of APUC, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 3,539,467 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 APUC 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 currently comprised of four directors of APUC, Mr. Ball (Chairman), Ms. Stapleton Barnes, Mr. Laney 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 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 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.

<table>
<thead>
<tr>
<th>Services</th>
<th>2016 Fees ($)</th>
<th>2015 Fees ($)</th>
<th>2014 Fees ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Audit Fees¹</td>
<td>2,765,607</td>
<td>2,420,650</td>
<td>1,965,600</td>
</tr>
<tr>
<td>Audit-Related Fees²</td>
<td>113,414</td>
<td>98,835</td>
<td>293,858</td>
</tr>
<tr>
<td>Tax Compliance Fees³</td>
<td>—</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>Other Tax Fees⁴</td>
<td>263,831</td>
<td>375,600</td>
<td>101,605</td>
</tr>
<tr>
<td>All Other Fees</td>
<td>5,800</td>
<td>19,500</td>
<td>28,000</td>
</tr>
</tbody>
</table>

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.
8.3 Corporate Governance, Risk and Compensation Committees

The Board has established a Corporate Governance Committee (“CGC”) currently comprised of four of the directors of APUC, Mr. Steeves (Chair), Mr. Moore, Ms. Saidi, and Mr. Jarratt.

In 2017, the Board has established a Risk Committee to assist the board in the oversight of the Corporation’s enterprise risk management approach. The committee is currently comprised of four directors of APUC, Ms. Saidi (Chair), Ms. Stapleton Barnes, Mr. Jarratt and Mr. Steeves.

The directors have also put in place a Compensation Committee (“CC”), currently comprised of four directors of APUC, Ms. Samil (Chair), Mr. Ball, and Mr. Laney and Ms. Saidi.

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, 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 MD&A for the fiscal year ended December 31, 2016, 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 was a major shareholder of APUC until December 8, 2016 and had a strategic relationship with the Corporation until January 13, 2017. 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 2016 are as follows:

(i) Trafalgar Proceedings

Trafalgar commenced an action in 1999 in U.S. District Court against the Corporation in connection with, among other things, the sale of the Trafalgar Class B Note by Aetna Life Insurance Company to the Corporation and certain affiliates of the Corporation and in connection with the foreclosure on the security for the Trafalgar Class B Note which includes interests in the Trafalgar entities and in hydroelectric generating facilities in New York (“Trafalgar Hydro Facilities”). Over the past 16 years there have been various District Court adversary proceedings and bankruptcy proceedings in connection with this matter.

By the end of July, 2015, the Trafalgar Hydro Facilities were all sold with the Bankruptcy Court’s approval.

In June, 2016, all of the above legal proceedings were settled pursuant to the terms outlined in the United States Bankruptcy Court for the Northern District of New York Order Approving Terms of Settlement which was entered into Bankruptcy Court on June 20, 2016. Pursuant to the global settlement, the Corporation and various Affiliates were allowed approximately U.S. $10.1 million which amount was received on June 30, 2016 (the “Litigation Proceeds”). The Litigation Proceeds were dispersed as more particularly outlined in the MD&A for the Nine Month Period Ending September 30, 2016 - Related Party Transactions.

(ii) Long Sault Global Adjustment Claim

In December 2012, N-R Power and Energy Corp., 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 as a price escalator. 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. On April 10, 2015, the OEFC appealed to the Court of Appeal to set aside the Divisional Court’s judgment of March 12, 2015. The appeal was heard on December 14 and December 15, 2015. The Ontario Court of Appeal dismissed the OEFC’s appeal by judgment dated April 19, 2016. OEFC sought leave to appeal to the Supreme Court of Canada (the “SCC”). In addition, OEFC brought a motion to stay the payment of the retroactive payments pending its appeal to the SCC. On August 5, 2016, the Court of Appeal denied OEFC’s motion for a stay. On September 13, 2016, the Ontario Court of Appeal dismissed the motion brought by the OEFC to set aside or vary the order. On October 21, 2016, the OEFC made retroactive payments of $5.1 million and $0.3 million of interest to Long Sault. On January 19, 2017, the SCC denied OEFC’s application for leave to appeal.

(iii) Côte Ste-Catherine Water Lease Dues

In October 2011, the Québec Court of Appeal ordered Mont-Laurier Partnership, a subsidiary of the Corporation, to pay approximately $5.4 million (including interest) to the Government of Québec relating to water lease payments that the APUC subsidiary has been paying to the St. Lawrence Seaway Management Corporation (“Seaway Management”) under its water lease with Seaway Management in prior years.

The water lease with Seaway Management contains an indemnification clause which management of the Corporation believes mitigates this claim and management intends to vigorously defend its position. As a result, the probability of loss, if any, and its quantification cannot be estimated at this time but could range from $nil to $6.9 million. In 2012, a subsidiary of the Corporation paid $1.9 million to the Government of Québec in relation to the early years covered by the claim in order to mitigate the impact of accruing interest on any amount ultimately determined to be payable or recoverable. The parties continue to engage in settlement discussions with a view to resolving this matter.

9.2 Regulatory Actions

Except as disclosed elsewhere in this AIF, during the financial year ended December 31, 2016, 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.

Except as disclosed elsewhere in this AIF, the only regulatory action involving APUC or its subsidiaries that is material in 2016 is as follows:

(i) Park Water Condemnation

Mountain Water is currently the subject of a condemnation lawsuit filed by the city of Missoula. On August 2, 2016, the Supreme Court of Montana upheld the District Court’s decision that the city of Missoula can proceed with condemnation of Mountain Water’s assets. Upon taking possession of Mountain Water’s assets, the compensation to be paid by the city of Missoula for such taking will be the value of the utility (determined by the valuation commissioners on November 17, 2015 to be U.S. $88.6 million as of May 6, 2014). Mountain Water is expected to receive certain additional amounts that may include legal fees, interest, post-valuation capital expenditures and property tax reimbursement.

On December 22, 2015, various developers filed a lawsuit in Missoula County District Court against Mountain Water and the city of Missoula. The lawsuit pertains to Funded By Other (FBO) contracts between each developer and Mountain Water. Under these FBO contracts, the developers paid for facilities to provide water service and Mountain Water agreed to refund such amounts over a 40 year period. As of the date of acquisition of Western Water Holdings, the outstanding balance of these advances, on a non-discounted basis, was U.S. $23.1 million. On February 21, 2017, the court issued an order imposing equitable liens on the Mountain Water assets that are the subject of the FBO contracts, mandating that the liens be satisfied directly from the condemnation award, if and when paid.

APUC expects that, in light of the foregoing and agreements entered in to at the time of the acquisition, the net amount to be recognized by APUC in connection with the conclusion of all such proceedings is reasonably likely to be at least $103 million. However, such amount remains uncertain in light of outstanding legal issues and proceedings and, as a result, no assurances can be given as to such amount.
On January 7, 2016, the Town of Apple Valley filed a lawsuit seeking to condemn the assets of Liberty Utilities (Apple Valley Ranchos Water) Corp. (formerly known as Apple Valley Ranchos Water Company). The Town of Apple Valley seeks to condemn the assets of Liberty Apple Valley along with a determination of fair market value. Liberty Apple Valley filed an answer to the condemnation complaint on February 23, 2016. In California, parties to a condemnation case typically agree for the case to be bifurcated in to two phases; initially to determine the necessity of the taking, and then, if the Town of Apple Valley is successful in the right to take proceeding, a second phase is held to determine the fair market value of the assets to be taken. The matter is expected to take two to three years to resolve. The condemnation action has potential financial implications for Liberty Utilities depending on the outcome of the condemnation process. In the event that the Town of Apple Valley prevails in the necessity phase of the condemnation case, the financial impact of the condemnation case will depend on the ultimate determination of the fair market value of Liberty Apple Valley’s assets by a jury if so elected by either party, along with a determination of interest and attorney’s fees by the court.

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 MD&A as at and for the periods ended December 31, 2016, 2015 and 2014, 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 listed on the TSX is CST Trust Company, at its offices in Toronto, Montréal, Vancouver, Calgary, and Halifax.

The transfer agent and registrar for the Common Shares listed on the NYSE is AST American Stock Transfer & Trust Company, LLC, at its office in Brooklyn, NY.

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 2016 (or prior to 2016 in the case of contracts that are still in effect) that are material to APUC:

(a) **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, as supplemented from time to time, including by the Fourth Supplemental Trust Indenture dated January 17, 2017 providing for the issuance of $300,000,000 4.09% senior unsecured debentures due February 17, 2027.

(b) **U.S. Debt Private Placements**: Trust Indenture dated July 2, 2012 between LU GP1 and The Bank of New York Mellon providing for the creation and issuance of senior unsecured debentures, as supplemented from time to time.

(c) **Empire Acquisition**: Agreement and Plan of Merger, dated as of February 9, 2016, by and among Empire, Liberty Utilities (Central) Co., and Liberty SubCo. pursuant to which Liberty Utilities (Central) Co. agreed to acquire Empire and (indirectly) its subsidiaries by merger of Liberty Sub Corp. with and into Empire. APUC guaranteed the payment and performance of all obligations of Liberty Utilities (Central) Co. under the Agreement and Plan of Merger pursuant to a Guarantee dated as of February 9, 2016, by APUC in favour of Empire.

(d) **Underwriting Agreement**: Underwriting Agreement dated February 15, 2016, between LU Canada, as the selling debenture holder, and CIBC World Markets Inc. and Scotia Capital Inc. as co-lead underwriters, providing for the issuance and sale of not less than $1,000,000,000 and up to $1,150,000,000 principal amount of Debentures in connection with the Instalment Debenture Offering.

(e) **Trust Indenture**: Trust Indenture dated as of March 1, 2016, between APUC and CST Trust Company, as trustee, providing for the creation and issuance of up to $1,150,000,000 principal amount of Debentures in connection with the Instalment Debenture Offering, as supplemented by a supplemental trust indenture dated January 31, 2017.

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 MD&A for the fiscal year ended December 31, 2016, which are available on SEDAR at www.sedar.com.
### Schedule A

#### Renewable - Hydroelectric, Solar and Wind Facilities

<table>
<thead>
<tr>
<th>Generating Facility/Owner</th>
<th>Generating Capacity (MW)</th>
<th>Location</th>
<th>Electricity Purchaser</th>
<th>Annual Average Expected Energy Production (GW-hrs)</th>
<th>PPA Expiry Year</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Hydroelectric - Ontario Facilities</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Facility: Long Sault Rapids Hydro Facility</td>
<td>18</td>
<td>Abitibi River near Cochrane, Ontario</td>
<td>Electricity Purchaser: OEFC</td>
<td>111.6</td>
<td>2048</td>
</tr>
<tr>
<td>Owner: Algonquin Power (Long Sault) Partnership and N-R Power Partnership</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Facility: Hurdman Dam Hydro Facility</td>
<td>0.6</td>
<td>Mattawa River near Mattawa, Ontario</td>
<td>Electricity Purchaser: IESO (formerly, the Ontario Power Authority)</td>
<td>0³</td>
<td>2031</td>
</tr>
<tr>
<td>Owner: Algonquin Power Fund (Canada) Inc.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Facility: Campbellford Hydro Facility</td>
<td>4</td>
<td>Trent River near Campbellford, Ontario</td>
<td>Electricity Purchaser: OEFC</td>
<td>26.3</td>
<td>2019</td>
</tr>
<tr>
<td>Owner: Algonquin Power (Campbellford) Limited Partnership</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Owner: Leased from Campbellford Public Utilities Commission, with lease expiring in 2018</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Hydroelectric – Québec Facilities</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Facility: Saint-Alban Hydro Facility</td>
<td>8.2</td>
<td>Ste-Anne River near the Village of Saint-Alban, Québec</td>
<td>Electricity Purchaser: Hydro-Québec</td>
<td>37.7</td>
<td>2016</td>
</tr>
<tr>
<td>Owner: Nominee owner is SNC Lavalin Inc., beneficial owner is Algonquin Power Fund (Canada) Inc.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Facility: Glenford Hydro Facility</td>
<td>5</td>
<td>Ste-Anne River near the Village of Ste-Christine d’Auvergne, Québec</td>
<td>Electricity Purchaser: Hydro-Québec</td>
<td>24</td>
<td>2020</td>
</tr>
<tr>
<td>Owner: Société en Commandite Chute Ford</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Facility: Generating Facility/Owner</td>
<td>Generating Capacity (MW)</td>
<td>Location</td>
<td>Electricity Purchaser</td>
<td>Annual Average Expected Energy Production (GW-hrs)</td>
<td>PPA Expiry Year</td>
</tr>
<tr>
<td>----------------------------------</td>
<td>--------------------------</td>
<td>----------</td>
<td>-----------------------</td>
<td>-----------------------------------------------</td>
<td>----------------</td>
</tr>
<tr>
<td>Rawdon Hydro Facility</td>
<td>2.5</td>
<td>Ouareau River near the Village of Rawdon, Québec</td>
<td>Hydro-Québec</td>
<td>15.2</td>
<td>2034</td>
</tr>
<tr>
<td>Owner: Algonquin Power Fund (Canada) Inc.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Côte Ste-Catherine Hydro Facility</td>
<td>11.1</td>
<td>St. Lawrence River near the Town of Ste.-Catherine, Québec</td>
<td>Hydro-Québec</td>
<td>Phase I: 13.8</td>
<td>Phase I: 2020</td>
</tr>
<tr>
<td>Owner: Algonquin Power Fund (Mont-Laurier) Limited Partnership</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Phase II: 35.1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Phase II: 2018</td>
</tr>
<tr>
<td>PPA has renewal option to 2043</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Phase III: 34.8</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Phase III: 2020</td>
</tr>
<tr>
<td>PPA has renewal option to 2045</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ste-Raphaël Hydro Facility</td>
<td>3.5</td>
<td>Rivière de Sud near Québec City, Québec</td>
<td>Hydro-Québec</td>
<td>21.7</td>
<td>2034</td>
</tr>
<tr>
<td>Owner: Algonquin Power Fund (Canada) Inc.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mont Laurier Hydro Facility</td>
<td>2.7</td>
<td>Rivière-du-Lièvre in the Town of Mont Laurier, Québec</td>
<td>Hydro-Québec</td>
<td>20.1</td>
<td>2027</td>
</tr>
<tr>
<td>Owner: Algonquin Power Fund (Mont-Laurier) Limited Partnership</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Rivière-du-Loup Hydro Facility</td>
<td>2.6</td>
<td>Rivière-du-Loup near the Town of Rivière-du-Loup, Québec</td>
<td>Hydro-Québec</td>
<td>17.3</td>
<td>2035</td>
</tr>
<tr>
<td>Owner: Algonquin Power Fund (Canada) Inc.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydraska Hydro Facility</td>
<td>2.3</td>
<td>Yamaska River near the Town of St.-Hyacinthe, Québec</td>
<td>Hydro-Québec</td>
<td>9.1</td>
<td>2034</td>
</tr>
<tr>
<td>Owner: Algonquin Power Trust</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ste-Brigitte Hydro Facility</td>
<td>4.2</td>
<td>Nicolet River in the Municipality of Ste-Brigitte-des-Saults, Québec</td>
<td>Hydro-Québec</td>
<td>12.6</td>
<td>2034</td>
</tr>
<tr>
<td>Owner: Algonquin Power Fund (Canada) Inc.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Facility/Owner</td>
<td>Generating Capacity (MW)</td>
<td>Location</td>
<td>Electricity Purchaser</td>
<td>Annual Average Expected Energy Production (GW-hrs)</td>
<td>PPA Expiry Year</td>
</tr>
<tr>
<td>----------------</td>
<td>---------------------------</td>
<td>----------</td>
<td>-----------------------</td>
<td>-----------------------------------------------</td>
<td>-----------------</td>
</tr>
<tr>
<td><strong>Generating Facility/Owner</strong></td>
<td><strong>Generating Capacity (MW)</strong></td>
<td><strong>Location</strong></td>
<td><strong>Electricity Purchaser</strong></td>
<td><strong>Annual Average Expected Energy Production (GW-hrs)</strong></td>
<td><strong>PPA Expiry Year</strong></td>
</tr>
<tr>
<td><strong>Facility:</strong> Belleterre Hydro Facility</td>
<td>2.2</td>
<td>Winneway River in the Municipality of Laforce, Québec</td>
<td>Electricity Purchaser: Hydro-Québec</td>
<td>11.2</td>
<td>2033</td>
</tr>
<tr>
<td><strong>Owner:</strong> Algonquin Power Fund (Canada) Inc.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Facility:</strong> Donnacona Hydro Facility</td>
<td>4.8</td>
<td>Jacques Cartier River near Donnacona, Québec</td>
<td>Electricity Purchaser: Hydro-Québec</td>
<td>21.5</td>
<td>2022 PPA has renewal option to 2047</td>
</tr>
<tr>
<td><strong>Owner:</strong> Société Hydro-Donnacona, S.E.N.C.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Facility:</strong> Arthurville Hydro Facility</td>
<td>0.7</td>
<td>Rivière du Sud downstream from Ste-Raphaël, Québec</td>
<td>Electricity Purchaser: Hydro-Québec</td>
<td>02</td>
<td>2033</td>
</tr>
<tr>
<td><strong>Owner:</strong> Algonquin Power Trust</td>
<td></td>
<td></td>
<td>Rates: No target rate as the site is expected to be offline</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### Hydroelectric - Western Canada Facility

| **Facility:** Dickson Dam Hydro Facility | 15 | Innisfail, Alberta | Electricity Purchaser: AESO & Capital Power | 65 | 2016 |
| **Owner:** Algonquin Power Operating Trust | | | | | |

### Hydroelectric - Maritime Facilities

| **Facility:** Tinker Hydro Facility | 34 | Perth-Andover, New Brunswick | Electricity Purchaser: AES Town of Perth-Andover | 142 | Perth-Andover Contract through 2021 |
| **Owner:** Algonquin Tinker Gen Co. | | | | | |

| **Facility:** Caribou Hydro Facility | 0.9 | Caribou, Maine | Electricity Purchaser: AES | 1.3 | n/a |
| **Owner:** Algonquin Northern Maine Gen Co. | | | | | |

| **Facility:** Squa Pan Hydro Facility | 1.4 | Squa Pan Lake, near Caribou, Maine | Electricity Purchaser: AES | 0.7 | n/a |
| **Owner:** Algonquin Northern Maine Gen Co. | | | | | |

### Solar Facilities

<p>| <strong>Facility:</strong> Cornwall Solar Facility | 10 | Cornwall, Ontario | Electricity Purchaser: IESO (formerly, the Ontario Power Authority) | 14.8 | 2034 |
| <strong>Owner:</strong> Cornwall Solar Inc. | | | | | |</p>
<table>
<thead>
<tr>
<th>Facility: Bakersfield Solar Facility</th>
<th>Generating Capacity (MW)</th>
<th>Location</th>
<th>Electricity Purchaser</th>
<th>Annual Average Expected Energy Production (GW-hrs)</th>
<th>PPA Expiry Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Owner: Algonquin SKIC20 Solar, LLC</td>
<td>20</td>
<td>Kern County, California</td>
<td>PG&amp;E</td>
<td>53.1</td>
<td>2035</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Rates: $0.883/kWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Facility: Bakersfield II Solar Facility</td>
<td>10</td>
<td>Kern County, California</td>
<td>(Southern California Edison Company)</td>
<td>26</td>
<td>2037 (20 years after COD)</td>
</tr>
<tr>
<td>Owner: Algonquin SKIC10 Solar, LLC</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Facility: Great Bay Solar Facility</td>
<td>75</td>
<td>Somerset County, Maryland</td>
<td>(Under Development - U.S. General Services Administration)</td>
<td>152</td>
<td>2027 (10 years after COD)</td>
</tr>
<tr>
<td>Owner: Great Bay Solar Holdings, LLC</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Wind - Canadian Facilities**

<p>| Facility: Morse Wind Facility       | 23                       | Morse, Saskatchewan | SaskPower | 108.8 | 2035 (20 years after COD) |
| Owner: Algonquin Power Morse LP    |                          |                      |                                                     |                                                   |                |
| Facility: Red Lily Wind Facility   | 26.4                     | Saskatchewan         | SaskPower | 88.4 | 2036 |
| Owner: Red Lily Wind Energy Partnership |                    |                      |                                                     |                                                   |                |
| Facility: St.-Damase Wind Facility | 24                       | Saint-Damase, Québec | Hydro-Quebec | 76 | 2034 |
| Owner: Société en Commandité Fleur de Lis Éoliennes Saint-Damase | | | | | |
| Facility: St. Leon Wind Facility   | 104                      | St. Leon, Manitoba   | Manitoba Hydro | 372 | 2026 + one 5 year extension |
| Owner: St. Leon Wind Energy LP     |                          |                      |                                                     |                                                   |                |
| Facility: St. Leon II Wind Facility| 16.5                     | St. Leon, Manitoba   | Manitoba Hydro | 58.1 | 2037 |
| Owner: St. Leon II Wind Energy LP  |                          |                      |                                                     |                                                   |                |</p>
<table>
<thead>
<tr>
<th>Facility/Owner</th>
<th>Generating Capacity (MW)</th>
<th>Location</th>
<th>Electricity Purchaser</th>
<th>Annual Average Expected Energy Production (GW-hrs)</th>
<th>PPA Expiry Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Val-Éo Wind Facility</td>
<td>24</td>
<td>Saint-Gédéon, Québec</td>
<td>Electricity Purchaser: (Under Development – Hydro-Quebec)</td>
<td>66</td>
<td>2037 (20 years after COD)</td>
</tr>
<tr>
<td>Éoliennes Belle-Rivière, société en commandite</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Amherst Island Wind Facility</td>
<td>75</td>
<td>Stella, Ontario</td>
<td>Electricity Purchaser: (Under Development - IESO [formerly, the Ontario Power Authority])</td>
<td>247</td>
<td>2038 (20 years after COD)</td>
</tr>
<tr>
<td>Windlectric Inc.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Chaplin Wind Facility</td>
<td>177</td>
<td>Chaplin, Saskatchewan</td>
<td>Electricity Purchaser: (Under Development - SaskPower)</td>
<td>720</td>
<td>2044/5 (25 years after COD)</td>
</tr>
<tr>
<td>Windlectric Inc.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wind - U.S. Facilities</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Minonk Wind Facility</td>
<td>200</td>
<td>Minonk, Illinois</td>
<td>Electricity Purchaser: PJM North Illinois</td>
<td>674</td>
<td>2022²</td>
</tr>
<tr>
<td>Minonk Wind, LLC</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Senate Wind Facility</td>
<td>150</td>
<td>Graham, Texas</td>
<td>Electricity Purchaser: ERCOT North markets</td>
<td>520</td>
<td>2027²</td>
</tr>
<tr>
<td>Senate Wind, LLC</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sandy Ridge Wind Facility</td>
<td>50</td>
<td>Tyrone, Pennsylvania</td>
<td>Electricity Purchaser: PJM West</td>
<td>158.3</td>
<td>2022²</td>
</tr>
<tr>
<td>Sandy Ridge Wind, LLC</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shady Oaks Wind Facility</td>
<td>109.5</td>
<td>Lee County, Illinois</td>
<td>Electricity Purchaser: Commonwealth Edison</td>
<td>352.4</td>
<td>2032</td>
</tr>
<tr>
<td>GSG6, LLC</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Odell Wind Facility</td>
<td>200</td>
<td>Cottonwood, Jackson, Martin and Watonwan Counties Minnesota</td>
<td>Electricity Purchaser: (Under Development - Northern States Power)</td>
<td>822</td>
<td>2036 (20 years after COD)</td>
</tr>
<tr>
<td>O'Dell Wind Farm, LLC.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Deerfield Wind Facility</td>
<td>150</td>
<td>Central Michigan</td>
<td>Electricity Purchaser: (Under Development – Wolverine Power Supply Co-operative)</td>
<td>555.2</td>
<td>2037 (20 years after COD)</td>
</tr>
<tr>
<td>Algonquin Power (Deerfield Holdings) Inc.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
1 Scheduled to be offline in 2017. No decision has been made as to the timing of repairing these facilities.

2 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”.
## Thermal - Biomass, Cogeneration, and Diesel Facilities

<table>
<thead>
<tr>
<th>Generating Facility/Owner</th>
<th>Generating Capacity (MW)</th>
<th>Location</th>
<th>Electricity Purchaser</th>
<th>Annual Average Expected Energy Production (GW-hrs)</th>
<th>Year of Expiry of PPA</th>
<th>Lease Expiry Year</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Thermal - Cogeneration Facilities</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Facility: Sanger Facility</td>
<td>56</td>
<td>Sanger, California</td>
<td>Electricity Purchaser: PG&amp;E</td>
<td>140.9</td>
<td>2021</td>
<td>Owned</td>
</tr>
<tr>
<td>Owner: Algonquin Power Sanger LLC</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Owner: Algonquin Power Windsor Locks LLC</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Facility: Kirkland Lake</td>
<td>132</td>
<td>Kirkland Land, Ontario</td>
<td>Electricity Purchaser: OEFC (Baseload) &amp; IESO (Gas Peaker)</td>
<td>657.8</td>
<td>2030 (Baseload) &amp; 2035 (Gas Peaking)</td>
<td>2035</td>
</tr>
<tr>
<td>Ownership: 32.4% of the Class B non-voting shares</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Thermal - Diesel Facilities</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Facility: Tinker Thermal Facility</td>
<td>1</td>
<td>Perth-Andover, New Brunswick</td>
<td>Electricity Purchaser: Not Under Contract Rates: Capacity only</td>
<td>0(^1)</td>
<td>NA</td>
<td>Owned</td>
</tr>
<tr>
<td>Owner: Algonquin Tinker Gen Co.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

\(^1\) 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.
<table>
<thead>
<tr>
<th>Utility</th>
<th>Owner</th>
<th>Location</th>
<th>Type of Utility</th>
<th>December 31, 2016 Connections</th>
<th>Rates²</th>
</tr>
</thead>
<tbody>
<tr>
<td>Black Mountain Sewer System</td>
<td>Liberty utilities (Black Mountain Sewer) Corp.</td>
<td>Carefree, Arizona</td>
<td>Wastewater</td>
<td>2,463</td>
<td>Pursuant to ACC decision 75510</td>
</tr>
<tr>
<td>Gold Canyon Sewer System</td>
<td>Liberty Utilities (Gold Canyon Sewer) Corp.</td>
<td>Gold Canyon Arizona</td>
<td>Wastewater</td>
<td>6,970</td>
<td>Pursuant to ACC decision 69664</td>
</tr>
<tr>
<td>Bella Vista Water System</td>
<td>Liberty Utilities (Bella Vista Water) Corp.</td>
<td>Sierra Vista, Arizona</td>
<td>Water Distribution</td>
<td>9,743</td>
<td>Pursuant to ACC decision 75809</td>
</tr>
<tr>
<td>Tall Timbers Waste System</td>
<td>Liberty Utilities (Tall Timbers Sewer) Corp.</td>
<td>Tyler, Texas</td>
<td>Wastewater</td>
<td>2,340</td>
<td>Pursuant to TCEQ decision 2009-1381-UCR and SOAH decision 582-10-0350</td>
</tr>
<tr>
<td>LPSCo Water &amp; Waste System</td>
<td>Liberty Utilities (Litchfield Park Water &amp; Sewer) Corp.</td>
<td>Litchfield, Park, Arizona</td>
<td>Wastewater Water Distribution</td>
<td>22,250 19,098</td>
<td>Pursuant to ACC docket 74437</td>
</tr>
<tr>
<td>Fox River Water &amp; Waste System</td>
<td>Liberty Utilities (Fox River Water) LLC</td>
<td>Sheridan, Illinois</td>
<td>Wastewater Water Distribution</td>
<td>245 241</td>
<td>Per customer agreement³ US $240.08 US $141.61</td>
</tr>
<tr>
<td>Timber Creek Water &amp; Waste System</td>
<td>Liberty Utilities (Missouri Water) LLC</td>
<td>DeSoto, Missouri</td>
<td>Wastewater Water Distribution</td>
<td>17 26</td>
<td>Pursuant to MOPSC decision WR-2006-4025</td>
</tr>
<tr>
<td>Holiday Hills Water System</td>
<td>Liberty Utilities (Missouri Water) LLC</td>
<td>Branson, Missouri</td>
<td>Water Distribution</td>
<td>502</td>
<td>Per MOPSC Case WR-2006-4025</td>
</tr>
<tr>
<td>Ozark Water &amp; Waste System</td>
<td>Liberty Utilities (Missouri Water) LLC</td>
<td>Kimberling City, Missouri</td>
<td>Wastewater Water Distribution</td>
<td>240 262</td>
<td>Pursuant to MOPSC decision WR-2006-4025</td>
</tr>
<tr>
<td>Holly Lake Water &amp; Waste System</td>
<td>Liberty Utilities (Silverleaf Water) LLC</td>
<td>Hawkins, Texas</td>
<td>Wastewater Water Distribution</td>
<td>137 2,011</td>
<td>Pursuant to TCEQ decision 2009-2087-UCR &amp; SOAH decision 582-10-2369</td>
</tr>
<tr>
<td>Big Eddy Water &amp; Waste System</td>
<td>Liberty Utilities (Silverleaf Water) LLC</td>
<td>Flint, Texas</td>
<td>Wastewater Water Distribution</td>
<td>424 551</td>
<td>Pursuant to TCEQ decision 2009-2087-UCR &amp; SOAH decision 582-10-2369</td>
</tr>
<tr>
<td>Piney Shores Water &amp; Waste System</td>
<td>Liberty Utilities (Silverleaf Water) LLC</td>
<td>Conroe, Texas</td>
<td>Wastewater Water Distribution</td>
<td>281 280</td>
<td>Pursuant to TCEQ decision 2009-2087-UCR &amp; SOAH decision 582-10-2369</td>
</tr>
<tr>
<td>Utility</td>
<td>Owner</td>
<td>Location</td>
<td>Type of Utility</td>
<td>December 31, 2016 Connections</td>
<td>Rates2</td>
</tr>
<tr>
<td>---------------------------------------</td>
<td>----------------------------------------------------------------------</td>
<td>-------------------------</td>
<td>---------------------------------</td>
<td>-------------------------------</td>
<td>--------</td>
</tr>
<tr>
<td>Hill Country Water &amp; Waste System</td>
<td>Liberty Utilities (Silverleaf Water) LLC</td>
<td>New Braunfels, Texas</td>
<td>Wastewater Water Distribution</td>
<td>425 230</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Northern Sunrise Water System</td>
<td>Liberty Utilities (Northern Sunrise Water) Corp.</td>
<td>Sierra Vista, Arizona</td>
<td>Water Distribution</td>
<td>370</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Southern Sunrise Water System</td>
<td>Liberty Utilities (Southern Sunrise Water) Corp.</td>
<td>Sierra Vista, Arizona</td>
<td>Water Distribution</td>
<td>896</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Entrada Del Oro Waste System</td>
<td>Liberty Utilities (Entrada Del Oro Sewer) Corp.</td>
<td>Gold Canyon, Arizona</td>
<td>Wastewater</td>
<td>350</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Seaside Resort Water &amp; Waste System</td>
<td>Liberty Utilities (Seaside Water) LLC</td>
<td>Galveston, Texas</td>
<td>Water Distribution</td>
<td>159 163</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Wastewater</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Noel Water System</td>
<td>Liberty Utilities (Missouri Water) LLC</td>
<td>Noel, Missouri</td>
<td>Water Distribution</td>
<td>687</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>KMB Water &amp; Waste System</td>
<td>Liberty Utilities (Missouri Water) LLC</td>
<td>Jefferson, Franklin and Cape Girardeau counties in Missouri</td>
<td>Wastewater Water Distribution</td>
<td>179 555</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pine Bluff Water System</td>
<td>Liberty Utilities (Pine Bluff Water) Inc.</td>
<td>Pine Bluff, Arkansas</td>
<td>Water Distribution</td>
<td>18,833</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>White Hall Water System</td>
<td>Liberty Utilities (White Hall Water) Corp., and Liberty Utilities (White Hall Sewer) Corp.</td>
<td>White Hall, Arkansas</td>
<td>Wastewater Water Distribution</td>
<td>1,852 1,949</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Liberty Utilities (Park Water) Corp.</td>
<td>Western Water Holdings, LLC</td>
<td>Downey, California</td>
<td>Water Distribution</td>
<td>27,413</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Liberty Utilities (Apple Valley Ranchos Water) Corp.</td>
<td>Liberty Utilities (Park Water) Corp.</td>
<td>Apple Valley, California</td>
<td>Water Distribution</td>
<td>20,349</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mountain Water Company</td>
<td>Liberty Utilities (Park Water) Corp.</td>
<td>Missoula, Montana</td>
<td>Water Distribution</td>
<td>22,933</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Woodson-Hensley Water Company</td>
<td>Liberty Utilities (Woodson-Hensley Water) Corp.</td>
<td>Hensley, Arkansas</td>
<td>Water Distribution</td>
<td>456</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total connections</strong></td>
<td></td>
<td></td>
<td></td>
<td><strong>177,194</strong></td>
<td></td>
</tr>
<tr>
<td>Utility</td>
<td>Owner</td>
<td>Location</td>
<td>Type of Utility</td>
<td>Connections Acquired January 1, 2017</td>
<td>Rates¹</td>
</tr>
<tr>
<td>---------------</td>
<td>-----------------------------------------</td>
<td>----------------</td>
<td>-----------------</td>
<td>-------------------------------------</td>
<td>--------------------</td>
</tr>
<tr>
<td>Empire</td>
<td>The Empire District Electric Company</td>
<td>Joplin, Missouri</td>
<td>Distribution</td>
<td>5,000</td>
<td>MO - ER-2016-0023</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>AR - 13-111-U</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>KS - 11-EPDE-856-RTS</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>OK - PUD 201100082</td>
</tr>
</tbody>
</table>

¹ Inclusive of vacant connections. Excludes connections associated with operating and maintenance contracts.
² See www.libertyutilities.com for complete rate tariffs.
³ Rates charged per agreement with developer.
### Electrical Distribution Facilities

<table>
<thead>
<tr>
<th>Utility</th>
<th>Owner</th>
<th>Location</th>
<th>Type of Utility</th>
<th>December 31, 2016 Connections¹</th>
<th>Rates²</th>
</tr>
</thead>
<tbody>
<tr>
<td>CalPeco Electric System</td>
<td>Liberty Utilities (CalPeco Electric) LLC</td>
<td>Lake Tahoe, California</td>
<td>Electricity Distribution</td>
<td>Residential – 42,946</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Commercial &amp; Industrial – 5,851</td>
<td></td>
</tr>
<tr>
<td>Granite State Electric</td>
<td>Liberty Utilities (Granite State Electric) Corp</td>
<td>Salem, New Hampshire</td>
<td>Electricity Distribution</td>
<td>Residential – 38,267</td>
<td></td>
</tr>
<tr>
<td>System</td>
<td></td>
<td></td>
<td></td>
<td>Commercial &amp; Industrial – 6,648</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Rates pursuant to NHPUC docket DE 13-063, Order 25,638</td>
<td></td>
</tr>
<tr>
<td>Total Connections</td>
<td></td>
<td></td>
<td></td>
<td>93,712</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Utility</th>
<th>Owner</th>
<th>Location</th>
<th>Type of Utility</th>
<th>Connections Acquired January 1, 2017</th>
<th>Rates²</th>
</tr>
</thead>
<tbody>
<tr>
<td>Empire</td>
<td>The Empire District Electric Company</td>
<td>Joplin, Missouri</td>
<td>Electricity Generation, Transmission &amp; Distribution</td>
<td>170,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>MO - ER-2016-0023</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>AR - 13-111-U</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>KS - 11-EPDE-856-RTS</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>OK - PUD 201100082</td>
<td></td>
</tr>
</tbody>
</table>

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

## Natural Gas Distribution Facilities

<table>
<thead>
<tr>
<th>Utility</th>
<th>Owner</th>
<th>Location</th>
<th>Type of Utility</th>
<th>December 31, 2016 Connections</th>
<th>Rates</th>
</tr>
</thead>
<tbody>
<tr>
<td>EnergyNorth Gas System</td>
<td>Liberty Utilities</td>
<td>Londonderry, New Hampshire</td>
<td>Natural Gas Distribution</td>
<td>81,059</td>
<td></td>
</tr>
<tr>
<td></td>
<td>(EnergyNorth Natural Gas)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Corp.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Peach State Gas System</td>
<td>Liberty Utilities</td>
<td>Columbus, Gainesville, GA</td>
<td>Natural Gas Distribution</td>
<td>60,233</td>
<td></td>
</tr>
<tr>
<td></td>
<td>(Peach State Natural Gas)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Corp.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>New England Gas System</td>
<td>Liberty Utilities</td>
<td>Fall River, North Attleboro,</td>
<td>Natural Gas Distribution</td>
<td>50,996</td>
<td></td>
</tr>
<tr>
<td></td>
<td>(New England Natural Gas</td>
<td>Plainville, Westport,</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Company) Corp.</td>
<td>Swansea, Somerset,</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Massachusetts</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Midstates Gas System - Illinois</td>
<td>Liberty Utilities</td>
<td>Salem, Virden, Vandalia,</td>
<td>Natural Gas Distribution</td>
<td>20,474</td>
<td></td>
</tr>
<tr>
<td></td>
<td>(Midstates Natural Gas)</td>
<td>Xenia, Metropolis,</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Corp.</td>
<td>Illinois</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Midstates Gas System - Iowa</td>
<td>Liberty Utilities</td>
<td>Keokuk, Iowa</td>
<td>Natural Gas Distribution</td>
<td>3,896</td>
<td></td>
</tr>
<tr>
<td></td>
<td>(Midstates Natural Gas)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Corp.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Midstates Gas System - Missouri</td>
<td>Liberty Utilities</td>
<td>Jackson, Sikeston, Butler,</td>
<td>Natural Gas Distribution</td>
<td>48,915</td>
<td></td>
</tr>
<tr>
<td></td>
<td>(Midstates Natural Gas)</td>
<td>Kirkville, Hannibal,</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Corp.</td>
<td>Missouri</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>New Hampshire Gas System</td>
<td>Liberty Utilities</td>
<td>Keene, New Hampshire</td>
<td>Propane Gas Distribution</td>
<td>744</td>
<td></td>
</tr>
<tr>
<td></td>
<td>(EnergyNorth Natural Gas)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Corp.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Total Connections**

| Total Connections | 293,491 |

---

## Connections Acquired January 1, 2017

<table>
<thead>
<tr>
<th>Utility</th>
<th>Owner</th>
<th>Location</th>
<th>Type of Utility</th>
<th>Connections</th>
<th>Rates</th>
</tr>
</thead>
<tbody>
<tr>
<td>Empire District Gas System</td>
<td>The Empire District Gas Company</td>
<td>Joplin, Missouri</td>
<td>Natural Gas Distribution</td>
<td>43,000</td>
<td>MO - ER-2016-0023 AR - 13-111-U KS - 11-EPDE-856-RTS OK - PUD 201100082</td>
</tr>
</tbody>
</table>

1 Inclusive of vacant connections. Excludes Transportation connections.

2 See www.libertyutilities.com for complete rate tariffs.
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, ramifications of the use of such alternative disclosure and treatments, and the treatment preferred by the external auditor, which discussion should address recognition, measurement and disclosure consideration related to the accounting for specific transactions as well as general accounting policies. Communications regarding specific transactions should identify the underlying facts, financial statement accounts impacted and applicability of existing corporate accounting policies to the transaction. Communications regarding general accounting policies should focus on the initial selection of, and changes in, significant accounting policies, the impact of the Management’s judgments and accounting estimates and the external auditor’s judgments about the quality of the Corporation’s accounting principles. Communications regarding specific transactions and general accounting policies should include the range of alternatives available under generally accepted accounting principles discussed by Management and the auditors and the reasons for selecting the chosen treatment or policy. If the external auditor’s preferred accounting treatment or accounting policy is not selected, the reasons 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 desirable in respect of the internal audit function.

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

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

(d) **Risk Assessment and Risk Management**

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

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

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

(e) **Legal Compliance**

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

(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.
GLOSSARY OF TERMS

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

“ACC” has the meaning ascribed thereto under “General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Liberty Utilities Group”.

“Acquisition Facility” has the meaning ascribed thereto under “General Development of the Business - Recent Developments - 2017 - Corporate”.

‘Empire Acquisition Credit Facilities” has the meaning ascribed thereto under “Caution Concerning Forward-Looking Statements and Forward-Looking Information”.

“ADEQ” has the meaning ascribed thereto under “Description of the Business - Liberty Utilities 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 - Business Development”.

“Alberta Power Pool” has the meaning ascribed thereto under "Description of the Business - Renewable Generation Group - Description of Operations - Hydroelectric Generating Facilities - Principal Markets and Distribution Methods".

“Ahlstrom” has the meaning ascribed thereto under "Description of the Business - Renewable Generation Group - Description of Operations - Thermal (Cogeneration) Electric Generating Facilities - Material Facilities".

“AIF” or “Annual Information Form” means this annual information form.

“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 - Name, Address and Incorporation”.

“APFA” means Algonquin Power Fund (America) Inc. See “Corporate Structure - Intercorporate Relationships - Subsidiaries”.

“APOT” means Algonquin Power Operating Trust. See “Corporate Structure - Intercorporate Relationships - Subsidiaries”.

“Apple Valley” means Liberty Utilities (Apple Valley Ranchos Water) Corp.

“Apple Valley Ranchos Water System” has the meaning ascribed thereto under "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 - Liberty Utilities 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”.
“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.

“Bakersfield I Solar Facility” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.

“Bakersfield II Solar Facility” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.


“Board” means the APUC Board of Directors.

“BRRBA” has the meaning ascribed thereto under “Description of the Business - Liberty Utilities Group - Description of Operations - Electric Distribution Systems - Principal Markets and Regulatory Environments”.

“CalPeco” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.

“CalPeco Electric System” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.

“COD” means commercial operation date.

“COG” has the meaning ascribed thereto under “Description of the Business - Liberty Utilities 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 - Renewable Generation Group - Description of Operations - Hydroelectric Generating Facilities - Material Facilities”.

“Cornwall Solar” means Cornwall Solar Inc. See “Corporate Structure - Intercorporate Relationships - Subsidiaries”.

“Cornwall Solar Facility” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.

“Corporate Credit Facility” has the meaning ascribed thereto under “Risk Factors - Treasury Risk - Interest Rate”.

“Corporate Term Facility” has the meaning ascribed thereto under “General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2016 - Corporate”.

“Côte Ste.-Catherine Hydro Facility” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group”.

“CPCN” has the meaning ascribed thereto under “Description of the Business - Liberty Utilities Group - Regulatory Regimes - Utility Distribution Systems.”

“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”.

“DBRS” means the credit rating agency Dominion Bond Rating Service Limited.

“Debentures” has the meaning ascribed thereto under “General Development of the Business - Recent Developments - 2017 - Corporate”.

“Default Service” has the meaning ascribed thereto under “Description of the Business - Liberty Utilities Group - Electric Distribution Systems - Material Facilities”.

“Deerfield Wind Facility” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group”.

“Dickson Dam Hydro Facility” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group”.

“Donnacona Hydro Facility” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.

“Donnaconna LP” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.

“EBITDA” means earnings before interest, taxes, depreciation and amortization.

“ECAC” has the meaning ascribed thereto under “Description of the Business - Liberty Utilities Group - Description of Operations - Electric Distribution Systems - Principal Markets and Regulatory Environments”.

“Emera” means Emera Inc. See “Description of Capital Structure - Private Placements of Subscription Receipts and Common Shares to Emera”.

“Empire” means Empire District Electric Company.

“Empire Acquisition” has the meaning ascribed thereto under “General Development of the Business - Recent Developments - 2016 - Corporate”.

“EnergyNorth Gas System” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.

“ERCOT” has the meaning ascribed thereto under “Description of the Business - Renewable Generation Group - Description of Operations - Wind Power Generating Facilities - Principal Markets and Distribution Methods”.

“ESA” has the meaning ascribed thereto under “Description of the Business - Renewable Generation Group - Description of Operations - Thermal (Cogeneration) Electric Generating Facilities - Material Facilities”.

“EWGs” has the meaning ascribed thereto under “Description of the Business - Renewable Generation Group - Regulatory Regimes-Power Generation - United States”.

“FERC” means the Federal Energy Regulatory Commission.

“FIT” means feed-in tariff.

“FPA” has the meaning ascribed thereto under “Description of the Business - Renewable Generation Group - Regulatory Regimes-Power Generation - United States”.

“FBO” means funded by others.

“Final Instalment” has the meaning ascribed thereto under “Description of Capital Structure - Convertible Debentures”.

“Final Instalment Date” has the meaning ascribed thereto under “Description of Capital Structure - Convertible Debentures”.

“GAAP” means Generally Accepted Accounting Principles.

“Gamesa” has the meaning ascribed thereto under “General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Renewable Generation Group”.

“Gold Canyon Water System” has the meaning ascribed thereto under “Description of the Business - Liability Utilities Group - Description of Operations - Water Distribution and Waste Water Collection Systems - Material Facilities”.
“GPSC” means Georgia Public Service Commission.

“GRAM” means the Georgia Rate Adjustment Mechanism.

“Great Bay Solar Project” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.

“Granite State Electric System” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.

“GW” means a gigawatt.

“Hydro-Québec” has the meaning ascribed thereto under “General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Renewable Generation Group”.

“IESO” has the meaning ascribed thereto under “General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Renewable Generation Group”.

“ISO” has the meaning ascribed thereto under “Description of the Business - Renewable Generation Group - Regulatory Regimes - Power Generation - Canada”.

“ISO-NE” has the meaning ascribed thereto under the heading “Description of the Business - Renewable 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 2014 - Liberty Utilities Group”.

“kV” means kilovolt.

“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 “Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group”.

“LLC” means Limited Liability Company.

“LPSCo System” has the meaning ascribed thereto under “General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Liberty Utilities Group”.


“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.

“MBR Authority” has the meaning ascribed thereto under “Description of the Business - Renewable Generation Group - Regulatory Regimes - Power Generation - United States”.

“Manitoba Hydro” means the Manitoba Hydro-Electric Board.

“MNR Authority” has the meaning ascribed thereto under “Description of the Business - Renewable Generation Group - Regulatory Regimes - Power Generation - United States”.

“Massachusetts” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.

“MD” means Maryland.

“MDR Authority” has the meaning ascribed thereto under “Description of the Business - Renewable Generation Group - Regulatory Regimes - Power Generation - United States”.

“Massachusetts” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.

“MDR Authority” has the meaning ascribed thereto under “Description of the Business - Renewable Generation Group - Regulatory Regimes - Power Generation - United States”.

“Massachusetts” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.

“MDR Authority” has the meaning ascribed thereto under “Description of the Business - Renewable Generation Group - Regulatory Regimes - Power Generation - United States”.

“Massachusetts” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.

“MDR Authority” has the meaning ascribed thereto under “Description of the Business - Renewable Generation Group - Regulatory Regimes - Power Generation - United States”.

“Massachusetts” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.

“MDR Authority” has the meaning ascribed thereto under “Description of the Business - Renewable Generation Group - Regulatory Regimes - Power Generation - United States”.

“Massachusetts” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.

“MDR Authority” has the meaning ascribed thereto under “Description of the Business - Renewable Generation Group - Regulatory Regimes - Power Generation - United States”.

“Massachusetts” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.

“MDR Authority” has the meaning ascribed thereto under “Description of the Business - Renewable Generation Group - Regulatory Regimes - Power Generation - United States”.

“Massachusetts” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.

“MDR Authority” has the meaning ascribed thereto under “Description of the Business - Renewable Generation Group - Regulatory Regimes - Power Generation - United States”.

“Massachusetts” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.

“MDR Authority” has the meaning ascribed thereto under “Description of the Business - Renewable Generation Group - Regulatory Regimes - Power Generation - United States”.

“Massachusetts” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.

“MDR Authority” has the meaning ascribed thereto under “Description of the Business - Renewable Generation Group - Regulatory Regimes - Power Generation - United States”.

“Massachusetts” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.

“MDR Authority” has the meaning ascribed thereto under “Description of the Business - Renewable Generation Group - Regulatory Regimes - Power Generation - United States”.

“Massachusetts” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.

“MDR Authority” has the meaning ascribed thereto under “Description of the Business - Renewable Generation Group - Regulatory Regimes - Power Generation - United States”.

“Massachusetts” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.

“MDR Authority” has the meaning ascribed thereto under “Description of the Business - Renewable Generation Group - Regulatory Regimes - Power Generation - United States”.

“Massachusetts” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.

“MDR Authority” has the meaning ascribed thereto under “Description of the Business - Renewable Generation Group - Regulatory Regimes - Power Generation - United States”.

“Massachusetts” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”. 
“MD&A” means the Corporation's management's discussion and analysis.

“Midstates Gas Systems” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries - Liberty Utilities Group”.

“Minonk Wind Facility” means the Minonk wind energy facility. See “Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group”.

“MMBTU” means one million British Thermal Units.

“Mont-Laurier Hydro Facility” means Mont-Laurier hydroelectric generating facility. See “Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group”.


“Moody’s” means Moody's Investors Services, Inc.

“Morse Wind Facility” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.

“MNESC” has the meaning ascribed thereto under “Description of the Business - Liberty Utilities Group - Description of Operations - Water Distribution and Waste Water Collection Systems - Principal Markets and Regulatory Environments”.

“Mountain Water” means Mountain Water Company.

“MPSC” has the meaning ascribed thereto under “General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Liberty Utilities Group”.

“MW” means megawatt.

“MVA” means mega-volt ampere.

“New England Gas System” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries - Liberty Utilities Group”.

“New Facility” has the meaning ascribed thereto under “General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2015 - Corporate”.


“NERC” means the North American Electric Reliability Corporation.


“NV Energy” means NV Energy, Inc.

“O&M” means an operation and maintenance service agreement.

“OATT” means open access transmission tariff.

“Odell Wind Facility” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group”.

“Odell SponsorCo” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group”.
“OEBC” means the Ontario Energy Board.

“OEC” 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” means the regulated water distribution utility, Park Water Company, now known as Liberty Utilities (Park Water) Corp.

“Park Water System” has the meaning ascribed thereto under “General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2016 - Liberty Utilities Group”.

“Peach State” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.

“Peach State Gas System” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.


“PGA” means Purchased Gas Adjustment.

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


“PPA” has the meaning ascribed thereto under “General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Renewable Generation Group”.

“PSU” has the meaning ascribed thereto under “Description of Capital Structure - Performance Share Units”.

“PTC” has the meaning ascribed thereto under “General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2016 - Renewable Generation Group Highlights”.

“PUHCA” has the meaning ascribed thereto under “Description of the Business - Renewable Generation Group - Regulatory Regimes-Power Generation - United States”.

“QFs” has the meaning ascribed thereto under “Description of the Business - Renewable Generation Group - Regulatory Regimes-Power Generation - United States”.

"Rating Agencies" means collectively DBRS, and S&P, and "Rating Agency" means one of the Rating Agencies.

“REC” has the meaning ascribed thereto under “General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Renewable Generation Group”.

“Red Lily Wind Facility” has the meaning ascribed thereto under “General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2016 - Renewable Generation Group Highlights”.

“Red Lily Partnership” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.

“Red Lily II LP” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.
“Renewable Generation Group” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.


“RPS” means renewable portfolio standards.

“S&P” means Standard & Poor’s Financial Services LLC.

“Saint-Damase Wind Facility” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group”.

“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 - Renewable Generation Group”.

“Sanger Thermal Facility” has the meaning ascribed thereto under “Description of the Business - Renewable Generation Group - Description of Operations - Thermal (Cogeneration) Electric Generating Facilities - Material Facilities”.

“SaskPower” means Saskatchewan Power Corporation.

“Senate Wind Facility” means the Senate wind energy facility.

“Series A Shares” has the meaning ascribed thereto under “Dividends - Preferred Shares”.

“Series C Shares” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group”.

“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 “Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group”.

“Squa Pan Hydro Facility” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group”.

“St. Alban Hydro Facility” means the St. Alban hydroelectric generating facility.

“St. Brigitte Hydro Facility” means the St. Brigitte hydroelectric generating facility.

“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 - Renewable Generation Group”.

“St. Leon Trust” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group”.

“St. Leon Wind Facility” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group”.

“Tinker Hydro Facility” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”
“TSX” means the Toronto Stock Exchange.

“Unit Exchange Transaction” has the meaning ascribed thereto under “Corporate Structure - Name, Address and Incorporation”.

“U.S. Wind Portfolio” has the meaning ascribed thereto under “General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Renewable Generation Group”.

“Val-Éo Wind Project” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.

“Windlectric” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries”.


“Windsor Locks Thermal Facility” has the meaning ascribed thereto under the heading “Description of the Business - Renewable Generation Group - Description of Operations - Thermal (Cogeneration) Electric Generating Facilities - Material Facilities”.

“White Hall Water System” has the meaning ascribed thereto under “General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Liberty Utilities Group”.

“White Hall Waste System” has the meaning ascribed thereto under “General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Liberty Utilities Group”.

“White Hall Water and Waste System” has the meaning ascribed thereto under “General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Distribution Group”.

“WP SponsorCo” has the meaning ascribed thereto under “Corporate Structure - Intercorporate Relationships - Subsidiaries - Renewable Generation Group”.