BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Joint Application of The Empire District Electric Company, Liberty Sub Corp. and Liberty Utilities (Central) Co. for Approval of an Agreement and Plan of Merger and for Other Related Relief	)))))	Docket No. 16-EPDE-410-ACQ

JOINT APPLICATION

The Empire District Electric Company ("Empire"), Liberty Sub Corp. ("LSC") and Liberty Utilities (Central) Co. ("LU Central") (collectively, "Joint Applicants"), pursuant to K.S.A. 66-101, *et seq*., 66-104, 66-117, 66-131, 66-136 and other applicable statutes and orders issued by the Kansas Corporation Commission ("Commission") seek an order authorizing LU Central to acquire all of the common stock of Empire and for other related relief. In support of their application, the Joint Applicants respectfully state as follows:

I. THE APPLICANTS

1. Empire is a Kansas Corporation with its principal office and place of business at 602 South Joplin Avenue, Joplin, Missouri 64801. Empire is qualified to conduct business and is conducting business in Kansas as well as in the states of Missouri, Arkansas and Oklahoma. Empire is engaged generally in the business of generating, purchasing, transmitting, distributing and selling electric energy in portions of said states. Empire also provides water utility service in Missouri. Through a wholly owned subsidiary, The Empire District Gas Company, Empire provides natural gas utility service in Missouri. Empire's Kansas electric utility operations are subject to the jurisdiction of the Commission as provided by law. A map showing the service area of Empire and a list of Kansas communities served by Empire is attached as **Appendix A** and incorporated herein by

reference.

2. A certified copy of Empire's restated Articles of Incorporation, as amended, has been previously filed with the Commission and is incorporated herein by reference. A certificate from the Kansas Secretary of State showing Empire is a Kansas corporation and is authorized to do business in Kansas, has been previously filed with the Commission and is incorporated herein by reference.

3. LU Central is a Delaware Corporation and was formed for the purpose of acquiring the capital stock of Empire as described herein. A Certificate of Good Standing from the office of the Delaware Secretary of State is attached hereto as **<u>Appendix B</u>** and incorporated herein by reference. LU Central is a wholly owned subsidiary of Liberty Utilities Co. ("Liberty Utilities") and is an indirect subsidiary of Algonquin Power & Utilities Corp. ("Algonquin"). LU Central is not a "public utility" as defined by K.S.A. 66-104 and will not become a public utility if this application is granted, although certain of its activities and transactions may be subject to K.S.A. 66-1401, *et seq*. governing affiliate transactions. A copy of LU Central's Bylaws is attached hereto as **<u>Appendix C</u>** and incorporated herein by reference. A copy of LU Central's Articles of Incorporation is attached hereto as **<u>Appendix D</u>** and incorporated herein by reference.

4. Liberty Sub Corp. ("LSC") is a Kansas corporation that is a wholly owned subsidiary of LU Central. LSC is a special purpose corporation formed for the sole purpose of merging with and into Empire as hereinafter described. A copy of LSC's Bylaws is attached hereto as **<u>Appendix E</u>** and incorporated herein by reference. A copy of LSC's Articles of Incorporation is attached hereto as **<u>Appendix F</u>** and incorporated herein by reference.

5. LU Central does not transact business in the State of Kansas. Consequently, it has not registered with the Secretary of State's office to do business in the State of Kansas as a foreign

corporation.

6. Pleadings, notices, orders, and other correspondence and communications concerning this Joint Application and proceeding should be addressed to the undersigned counsel as well as to:

Kelly Walters
VP-COO Electric
The Empire District Electric Company
602 South Joplin
Joplin, Missouri 64801

Scott Keith
Director, Planning and Regulatory
The Empire District Electric Company
602 South Joplin
Joplin, Missouri 64801

Christopher D. Krygier
Director, Regulatory and Government Affairs
Liberty Utilities
2751 N. High Street
Jackson, Missouri 63755

Sarah B. Knowlton
Senior Director, Regulatory Counsel
Liberty Utilities
15 Buttrick Road
Londonderry, NH 03053

II. ASSOCIATED ENTITIES

7. Algonquin is a publicly traded corporation registered on the Toronto Stock Exchange and is incorporated under the laws of Canada, with a principal place of business in Oakville, Ontario. Algonquin has three business units: (i) a power generation unit, Algonquin Power Co., that includes 345 renewable power generating facilities representing over 1,150 MW of installed generating capacity, (ii) a utility service unit, Liberty Utilities (Canada) Corp., that owns and operates regulated utilities located in eleven states that provide retail water, sewer, electric and natural gas utility service

to approximately 560,000 customers, and (iii) a recently formed transmission group responsible for evaluating and capitalizing upon natural gas pipeline and electric transmission asset opportunities in North America. Algonquin is not a "public utility" as defined in K.S.A. 66-104, and will not become a public utility if this application is granted. A copy of Algonquin's 2014 Annual Report is attached hereto as **Appendix G** and is incorporated herein by reference. A copy of the current Liberty Utilities (Canada) Corp. corporate organizational chart is attached as **Appendix H** and is incorporated herein by reference.

III. THE TRANSACTION

8. Empire, LU Central and LSC have entered into an Agreement and Plan of Merger dated February 9, 2016, ("Agreement"), a copy of which is attached hereto as **Appendix I** and incorporated herein by reference. Pursuant to the Agreement, LSC will be merged with and into Empire under the terms and provisions described in the Agreement, with Empire emerging as the surviving corporation. Immediately following the merger LSC will cease to exist. As a consequence of the merger, Algonquin will acquire, indirectly through its subsidiary LU Central all of the capital stock of Empire. Empire's outstanding debt and related obligations will remain with Empire.

9. The aggregate purchase price of the transaction is $2.4 billion dollars, including $.9 billion of existing Empire indebtedness. Empire's shareholders will receive $34 per common share in cash. A copy of the confidential letter of commitment from the banks involved in the transaction is attached as **Appendix J** and incorporated herein by reference. On March 2, 2016, an offering by Algonquin of mandatorily convertible debentures associated with this transaction was successfully completed and reflected robust demand for the securities comprising the offering.

10. Closing of the transaction is subject to customary conditions, including the approval

of Empire's common shareholders and the receipt of certain state and federal regulatory and governmental approvals, including the approval of this Commission.

11. At the closing of the transaction, Empire will become a wholly owned subsidiary of LU Central and will cease to be a publicly held corporation. A copy of the Liberty Utilities (Canada) Corp. organizational chart post Empire merger is attached as **Appendix K** and incorporated herein by reference.

12. A certified copy of the Resolutions of the Board of Directors of Empire authorizing the transaction and related matters contemplated by the Agreement is marked **Appendix L**, attached hereto and made a part hereof for all purposes.

13. Certified copies of the Resolutions of the Board of Directors of LSC and LU Central authorizing the transaction and related matters contemplated by the Agreement are marked **Appendix M**, attached hereto and made a part hereof for all purposes.

IV. JURISDICTION OF THE COMMISSION

14. Joint Applicants seek approval pursuant to K.S.A. 66-131 and 66-136, of the acquisition by LU Central of Empire's capital stock pursuant to the terms of the Agreement.

15. The certificates of convenience and authority, rates and tariffs will be held in the name of Empire, a wholly owned subsidiary of LU Central, and Empire will continue doing business under the Empire name.

V. THE PROPOSED TRANSACTION WILL PROMOTE THE PUBLIC INTEREST

16. LU Central's acquisition of Empire's utility operations in Kansas, Missouri, Oklahoma and Arkansas, and the combination of those operations with Liberty Utilities' existing utility operations, is a logical extension of Liberty Utilities' business and will result in many benefits that will

inure to the customers, employees, regulators, and shareholders of both Empire and Liberty Utilities. Empire's utility operations and Liberty Utilities' utility operations have similar customer profiles, community demographics, cultures and business relationships. A map showing the location of Liberty Utilities' utility operations in Missouri, Arkansas, Iowa, Illinois, and Texas and Empire's utility operations in Kansas, Missouri, Oklahoma and Arkansas is attached as **Appendix N** and incorporated herein by reference.

17. LU Central's acquisition of Empire is in the public interest and meets or surpasses the criteria established by this Commission to determine if a merger or acquisition is in the public interest.[1]

18. The proposed acquisition of the capital stock of Empire by LU Central is in and will promote the public interest in the following respects:

a. The electric utility assets of Empire will remain subject to the jurisdiction of the Commission and the transaction will not impair or impede the nature or scope of the Commission's supervision of Empire's operations.

b. Empire will continue to comply with any ongoing regulatory commitments as are currently in place with respect to its electric operations.

c. This transaction represents an opportunity to increase the size of the respective organizations to nearly 800,000 combined customers providing service across thirteen states with expertise in water, gas, and electric utilities. This scale is expected to result in greater management expertise, access to broader management capabilities, and an ability to capitalize

[1]KPL/KGE Merger Order dated November 15, 1991, Docket Nos. 172,745-U and 174,155-U (pages 35-36 list factors that will be considered by the Commission to determine whether the proposed transaction will promote the public interest ("KPL/KGE Merger Case").

on greater opportunities for future efficiencies. In addition, by combining the expertise of both companies, a joint entity will now enjoy expertise in electric utility operations of over 270,000 customers including vertical integration with utility owned and developed renewable energy and conventional generation fleet.

d. Empire will have access to renewable energy development expertise that has already proven to be beneficial to Liberty Utilities' electric utilities it owns in other jurisdictions with investments in utility owned solar generation that is expected to reduce overall customer energy costs.

e. Empire will maintain its headquarters in Joplin, Missouri after the transaction is closed and its employees and experienced management team will remain in place evidencing Liberty Utilities' commitment that Empire will continue to provide customers with safe, reliable and cost-effective utility service.

f. Empire and several of Liberty Utilities' existing utilities will operate within a new region ("Liberty Central"), with Bradley Beecher, the current CEO of Empire assuming the role of the CEO of LU Central. The entities within Liberty Central will be Empire, Liberty Utilities' natural gas utilities located in Missouri, Illinois and Iowa, and Liberty Utilities' water and wastewater utilities located in Arkansas, Missouri and Texas. Combined, approximately 340,000 customers will be served by LU Central.

g. A regional board of directors will be established consisting of senior business and community leaders. This board is expected to provide guidance and counsel on local issues to ensure that the combined entity will enhance its understanding of local operating conditions and be able to better serve the needs of customers. The board will have commensurate fiduciary duties, and all existing board members of Empire will be offered a position on the board.

h. Empire will continue to utilize the rates, rules, regulations and other tariff provisions on file with and approved by the Commission, and will continue to provide service to its customers under those rates, rules and regulations, and other tariff provisions until such time as they may be modified according to applicable law. As a consequence, the transaction will have no discernable effect on existing Empire customers, all of whom will continue to experience quality day to day service at just and reasonable rates without incident or interruption and LU Central and Empire expect a seamless transition. The Joint Applicants will mail notice to all of Empire's Kansas customers advising them of the proposed transaction and this Joint Application. A copy of the proposed notice to be sent to all customers will be submitted to the Commission Staff for its review and approval. Once the notice is approved by the Commission Staff, it will be mailed to all Kansas customers.

i. Liberty Utilities and its subsidiaries operate under a shared services model pursuant to which certain corporate and business services are provided to the operating businesses from affiliates and charged to these utilities based on either a direct charge or defined cost allocation methodology. A copy of Algonquin's current cost allocation manual is attached hereto as **Appendix O** and is incorporated herein by reference. As detailed in the testimony of LU Central witness Eichler, Liberty Utilities' cost allocation process is based on the framework established by the National Association of Regulatory Utility Commissioners on affiliate transactions, and this process is used by all of Algonquin's regulated and non-regulated companies. The cost allocation manual explains how all costs are direct charged where possible which provides for transparency, and where allocated, the cost in question is linked to drivers of the cost to ensure fairness, equity and no cross-subsidization among regulated utility affiliates and non-regulated affiliates. The cost allocation manual and the underlying principles, procedures, controls and safeguards protect regulated utility customers so that they only receive their fair share of costs. Algonquin will revise or modify its current cost allocation manual to reflect the acquisition of Empire within six (6) months following the closing of the transaction. As part of this Joint Application, Liberty Utilities agrees to comply with the Standards for Affiliate Transactions set forth in K.S.A. 66-1213a, 66-1401, 66-1402 and any Commission order, rule or regulation addressing affiliate transactions and the recovery of costs from affiliates.

j. The Joint Applicants anticipate that LU Central's parent, Liberty Utilities Co., will maintain a strong investment grade credit rating, and that it therefore will be able to access the capital markets on reasonable terms for the benefit of its regulated operations, including those of Empire. A balance sheet and income statement for the 12 months ending December 31, 2015, of Empire is attached hereto as **Appendix P** and is incorporated herein by reference. A proforma balance sheet and income statement of the merged entity is attached as **Appendix Q** to this Application and is incorporated herein by reference.

k. The transaction will have no impact on the property tax revenues of any political subdivision in which any of the structures, facilities, or equipment of Empire are located.

l. LU Central will not seek any recovery of the transaction costs or premium paid over the net book value of the utility assets in future rate cases.

m. Liberty Utilities has a demonstrated record of continuing to make investments in utility infrastructure to ensure reliability; maintaining high levels of service; and taking a proactive approach to managing the supply requirements of its customer base. Liberty Utilities has maintained an active partnership with and dedication to the communities it serves. Liberty Utilities has also demonstrated a respectful and open relationship with regulators.

n. The transaction is expected to be beneficial to the shareholders of both companies. The transaction will forge financially stronger utility operations and provide a solid foundation for future growth in earnings per share and increased shareholder value.

o. The transaction will not result in increased costs to Empire's cost of service. As LU Central witnesses Pasieka and Eichler explain, there are opportunities for savings as a result of the merger due to elimination of redundant costs between the organizations such as SEC registration fees and other public listing costs, as well as increased scale that may be achieved across the Liberty Utilities organization.

VI. Identification of Witnesses that Have Direct Testimony in Support of the Joint Application

19. In support of this Joint Application, the following witnesses have prepared and prefiled direct testimony and exhibits on behalf of Empire and LU Central:

a. Brad Beecher, President of Empire provides testimony on behalf of Empire. Mr. Beecher describes Empire's current operations and affirms that they will continue to be conducted under new ownership just as they have in the past and that the transaction will have a positive long term impact on Empire's customers and employees.

b. The following witnesses provide testimony and exhibits on behalf of LU Central: David Pasieka, Peter Eichler, and Christopher D. Krygier. Their direct testimony and exhibits include information about Algonquin, Liberty Utilities and their utility and non utility businesses and their experience in operating those companies and serving their customers and describe the transaction and transition plan. They explain how the transaction will promote the public interest based upon the factors or criteria adopted by the Commission in the KPL/KGE Merger Case, which are applicable to the present transaction, and explain how Algonquin and Liberty Utilities are qualified to own and operate Empire's utility business. They sponsor the financial information filed with this Joint Application, which demonstrates that Algonquin and Liberty Utilities have the financial capability to operate Empire's utility business. They explain how Liberty Utilities plans to operate Empire's utility business. Their testimony includes a discussion of how Liberty Utilities intends to retain the Empire employees and to adopt Empire's tariff rates, rules and regulations.

WHEREFORE, Joint Applicants request that the Commission issue an order:

(a) authorizing, consenting to and approving Empire and LU Central to consummate the transaction in accordance with the terms and conditions of the Agreement and Plan of Merger and all other transaction related instruments, and to take any and all other actions as may be reasonably necessary and incidental to the performance of the transaction;

(b) authorizing LU Central, pursuant to the terms of the Agreement and Plan of Merger, to acquire all of the stock of Empire all as more particularly described in the Agreement;

(c) authorizing Empire to merge with LSC with Empire being the surviving corporation, all as more particularly described in the Agreement and Plan of Merger;

(d) authorizing the post-merger Empire to retain Empire's current tariff rates, rules and regulations, including Empire's ECA and ACA tariffs, AVTS tariff, AECR rider, and remaining under recovered/over recovered balances, if any, under those tariffs, and franchises, certificates, consents and permits relating to the operation of the electric utility's plant and facilities;

(e) finding that the transaction and other relief sought in this Joint Application is in the public interest; and

(f) granting such other relief deemed by the Commission to be just and proper to accomplish the purpose of this Joint Application and to consummate the transaction described herein.

James G. Flaherty, #11177
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<u>VERIFICATION</u>

STATE OF KANSAS, COUNTY OF FRANKLIN, ss:

James G. Flaherty, of lawful age, being first duly sworn on oath, states:

That he is the attorney for Joint Applicants named in the foregoing Joint Application, and is duly authorized to make this affidavit; that he has read the foregoing Joint Application and knows the contents thereof; and that the facts set forth therein are true and correct.

James G. Flaherty

SUBSCRIBED AND SWORN to before me this 15th day of March, 2016.

NOTARY PUBLIC - State of Kansas
RONDA ROSSMAN
My Appt. Exp. 5/25/2018

Notary Public

Appointment/Commission Expires:

BEFORE THE STATE CORPORATION COMMISSION
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DIRECT TESTIMONY OF BRAD P. BEECHER

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Brad P. Beecher, and my business address is 602 S. Joplin Avenue, Joplin, Missouri, 64801.

Q. WHO IS YOUR EMPLOYER AND WHAT POSITION DO YOU HOLD?

A. The Empire District Electric Company ("Empire" or "Company") is my employer. I hold the position of President and Chief Executive Officer.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND.

A. I graduated from Kansas State University in 1988 and hold a Bachelor of Science Degree in Chemical Engineering.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. I was first employed by Empire in May 1988 through August 1999. During that time, I held roles as a Staff Engineer at Empire's Riverton power plant, and in budgeting and fuel procurement in Empire's Energy Supply Department. In 1995, I became Director of Strategic Planning. I held that position until I left Empire in August 1999. Between August 1999 and February 2001, I was employed at Black & Veatch in various roles including, Service Area

Leader for the Strategic Planning Group and as Associate Director of Marketing and Strategic Planning. I rejoined Empire as General Manager-Energy Supply in February 2001. I was elected Vice President-Energy Supply in April 2001. In this position, I was responsible for Empire's energy supply function including power plant construction, operation and maintenance and fuel procurement. In April 2006, I became the Electric Chief Operating Officer, and, in February 2010, I was named Executive Vice President. I assumed my current position in June 2011.

Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY BEFORE THIS COMMISSION?

A. Yes, I have presented testimony before the Kansas Corporation Commission ("Commission").

Q. PLEASE DESCRIBE EMPIRE.

A. Empire is a Kansas corporation with its principal office and place of business at 602 S. Joplin Avenue, Joplin, Missouri 64801. Empire is engaged in the business of providing electric utility services in Missouri, Kansas, Arkansas and Oklahoma: water utility service in Missouri; and, through a wholly-owned subsidiary, certain telecommunications services. In addition, through a wholly-owned subsidiary, The Empire District Gas Company, Empire operates a natural gas distribution business in northwest, north central and west central Missouri, providing regulated natural gas service in 48 communities.

Q. PLEASE DESCRIBE THE AREA SERVED BY EMPIRE.

A. Empire provides electric service in an area of approximately 10,000 square miles in the southwest corner of Missouri and reaches into adjacent corners of the states of Kansas, Oklahoma, and Arkansas. Empire's operations are regulated by the utility regulatory commissions of these four states as well as the Federal Energy Regulatory Commission ("FERC"). The area embraces 119 incorporated communities in 21 counties in the four-state area. Most of the communities in Empire's service area are small, with only 32 containing a population in excess of 1,500. Only ten (10) communities have a population in excess of 5,000, and the largest city, Joplin, Missouri, has a population of approximately 50,000. The economy in our service area is diversified, featuring small to medium manufacturing operations, agricultural, entertainment, tourism and retail interests.

Q. HOW MANY ELECTRIC CUSTOMERS DOES EMPIRE CURRENTLY SERVE?

A. At December 31, 2015, Company-wide, Empire served approximately 143,271 residential customers, 24,405 commercial customers, 353 industrial customers, 2,080 public authority and street and highway customers, and four wholesale customers. As of December 31, 2015, in Kansas, Empire served approximately 8,231 residential customers, 1,212 commercial customers, 49 industrial customers, 174 public authority and street and highway customers, and one wholesale customers.

II. EXECUTIVE SUMMARY

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. The purpose of my testimony is to provide support for the Joint Application ("Joint Application") filed by Empire and Liberty Utilities (Central) Corp. ("LU Central"). The Joint Application seeks an order authorizing the applicants to take certain actions, the results of which will, among other things, permit the acquisition by Algonquin Power & Utilities Corp. ("Algonquin") (through its wholly-owned subsidiary, LU Central, of all of the capital stock of Empire, all as more detailed in the Agreement and Plan of Merger (the "Agreement") executed on February 9, 2016. A copy of the Agreement is attached to the Joint Application as Appendix I. In that regard, I will provide certain information about Empire's operations and other information as is pertinent to the transaction. Among other things, I will provide an explanation as to why the transaction will promote the public interest and, consequently, why it should be approved by the Commission subject to the conditions proposed in the Joint Application.

Q. WHY HAVE EMPIRE AND LU CENTRAL FILED THE JOINT APPLICATION?

A. As noted above, the Transaction involves the acquisition by LU Central of Empire, with Empire becoming a subsidiary of LU Central. Because the Transaction involves a merger by Empire, it must be submitted for the Commission's consideration and approval as contemplated by Kansas law (K.S.A. 66-136). The Joint Application has been filed to comply with this requirement.

Q. PLEASE PROVIDE THE BACKGROUND FOR THE TRANSACTION.

A. On December 13, 2015, the Board announced it had engaged a financial advisor to explore strategic alternatives for the Company. As a result of those efforts the Board announced on February 9, 2016, it had approved an agreement and plan of merger whereby LU Central would acquire Empire and its subsidiaries. The transaction benefits Empire's stakeholders by providing benefits to customers, shareholders, and employees alike. Specifically, the transaction benefits Empire and its customers by providing increased corporate capability and scale by making Empire part of the Algonquin family of utility companies. Following the transaction, Empire will maintain the strong, investment-grade credit rating it will need to address future industry risks and trends. This is addressed further in the testimony of David

Pasieka.

Q. PLEASE EXPLAIN THE NATURE OF THE TRANSACTION THAT IS THE SUBJECT OF THE APPLICATION IN THIS CASE.

A. Algonquin operates a U.S.-based subsidiary known as Liberty Utilities Co. ("Liberty Utilities"). Liberty Utilities owns regulated electric, natural gas, and water utilities serving approximately 560,000 customers across the U.S. In the central part of the country, Liberty Utilities owns natural gas local distribution properties in Missouri, Iowa and Illinois that serve about 83,000 customers. Liberty Utilities also owns regulated water distribution utilities in Missouri, Arkansas and Texas that serve a total of 43,000 customers. Assuming the Commission approves the transaction, Empire will become an indirect subsidiary of Liberty Utilities. As part of the transaction, Liberty Utilities has committed to maintaining Joplin, Missouri, as the regional headquarters for all regulated utilities owned by Liberty Utilities in the mid-western states of Missouri, Iowa, Illinois, Arkansas, Oklahoma, Kansas, and Texas. A description of the transaction as contemplated by the Agreement and a further description of how Empire's operations will fit into Liberty Utilities' business is more fully addressed by witnesses David Pasieka, Peter Eichler and Christopher Krygier.

Q. PLEASE DESCRIBE YOUR UNDERSTANDING OF THE ISSUE THAT IS PRESENTED FOR THE COMMISSION'S DETERMINATION CONCERNING THE TRANSACTION DESCRIBED IN AND PRESENTED IN THE JOINT APPLICATION.

A. Although I am not an attorney, as I understand it the Commission must approve the Joint Application so long as the transaction will promote the public interest.

Q. WILL THE PROPOSED TRANSACTION PROMOTE THE PUBLIC INTEREST?

A. Yes. There will be no impact on customers with respect to rates or service as a result of the transaction, and as described below as well in the testimony of Mr. Pasieka, there will be a positive long term impact on Empire's customers and employees as a result of the transaction. Liberty Utilities has committed to make Joplin the regional headquarters for all regulated utilities owned by Liberty Utilities in the central states. Liberty Utilities also has committed to retain all of Empire's management team, its workforce following closing of the transaction, and will continue to operate Empire's business under the Empire brand for at least five years.

Q. WILL THE BOARD OF DIRECTORS BE RETAINED?

A. A regional board of directors will be established to provide guidance and counsel on local issues and enhanced customer service. All existing board members of Empire will be offered a position on the board.

Q. PLEASE ELABORATE ON THE IMPACT ON EMPIRE'S EMPLOYEES.

A. Empire has a dedicated and skilled workforce of managers, administrators and professional and field staff with expertise in regulated utility operations that has a strong reputation for delivering excellent customer service. The transaction will not result in any involuntary reductions in Empire's current administrative, professional, and field workforce and its existing management team will be retained. In fact, the transaction likely will lead to an expansion of employment opportunities as Empire's management team continues to oversee Empire's ongoing operations and assumes additional responsibility for the oversight management of Liberty Utilities other operations in the central United States. Through the expertise of the employees at Empire and Liberty Utilities, the capabilities of both organizations will be enhanced.

Q. PLEASE DISCUSS THE IMPACT ON CUSTOMERS.

A. Empire's customers will see no change in their day-to-day utility service or rates and they will continue to be served safely, effectively, and efficiently without interruption by the same employees who serve them today. The day-to-day operations of Empire in Kansas will continue as they have in the past, and continue to be regulated by and be subjected to review by the Commission. As a result of the transaction, Empire customers will be served by a larger, more capable organization. Our customers will also see Empire continue its current level of involvement and charitable support for our local communities.

We believe the merger will provide opportunities for our customers, employees, and shareholders to achieve benefits that would not be available if Empire were to remain an independent company, and that the merger will result in a combined company that will be well positioned to succeed going forward. The merger adds scale for both Empire and LU Central, thus providing opportunities to pursue efficiencies, share costs across a larger customer base, leverage best practices, and enhance service offerings. The inherent increase in scale and market diversification will also provide increased financial stability and strength, which could not be achieved without the combination of the companies. The increased geographic footprint will also diversify risk surrounding weather events.

Q. WILL THE PROPOSED TRANSACTION CHANGE EMPIRE'S STATUS AS A REGULATED ELECTRIC UTILITY IN KANSAS?

A. No. As a subsidiary of LU Central, Empire's utility operations will continue to be regulated by each of the five regulatory commissions that currently regulate Empire, including this Commission.

Q. HAS THE AGREEMENT BEEN APPROVED BY THE BOARD OF DIRECTORS OF EMPIRE?

A. Yes. A copy of the resolutions of the Board of Directors of Empire approving the Agreement and the transaction and authorizing the execution of the Agreement is attached to the Joint Application as Appendix L.

Q. PLEASE CHARACTERIZE LIBERTY UTILITIES AS A MERGER PARTNER.

A. We are confident that LU Central is the right merger partner.

Q. WHY?

A. It has been Empire's opinion that for a utility merger to be truly beneficial certain consistent core values must exist in the merger partner. Certainly, financial parameters must be achieved in the merger for the company giving up control, but if the resulting entity is not committed to the core values of providing a positive customer experience, continuous improvement, regulatory compliance, commitment to our community and focus on safety, the long-term effects of the merger will not be maximized. We believe that Liberty Utilities has exhibited these core values in its proposal by establishing Joplin as the regional headquarters for LU Central, retaining all employees, demonstrating a history of providing safe, reliable service to customers and committing to continue to operate the existing businesses under the Empire brand. The merger provides an opportunity to form an outstanding utility, including the Liberty Utilities' current central United States operations. These factors coupled with Liberty Utilities' experience in its other markets, investment grade financial strength, and its affiliate's expertise in the renewable energy market led us to the conclusion that LU Central is the right merger partner for all concerned, including customers, employees, regulators and shareholders.

Q. DOES THE TRANSACTION NEED TO BE APPROVED BY EMPIRE'S SHAREHOLDERS?

A. Yes. A simple majority of the outstanding shares of common stock must vote in favor of the merger for it to be approved.

Q. PLEASE DESCRIBE HOW THE SHAREHOLDER VOTE ON THE TRANSACTION WILL BE STRUCTURED.

A. Each share of common stock will be entitled to one vote that may be voted for or against the Agreement as presented. We estimate that a proxy containing detailed information about the Agreement will be mailed to each stockholder this spring. The proxy will announce a meeting of the stockholders to be held sometime this summer.

Q. EMPIRE HAS COMMITTED TO FILING A GENERAL RATE CASE NO LATER THAN SEPTEMBER 30, 2016, AS PART OF AN AGREEMENT APPROVED BY THE COMMISSION IN DOCKET NO. 15-EPDE-233-TAR. DOES EMPIRE STILL PLAN TO FILE A RATE CASE UNDER THAT AGREEMENT?

A. Yes. The transaction will have no impact on Empire's agreement to file a general rate case no later than September 30, 2016.

Q. WILL THE TRANSACTION HAVE ANY IMPACT ON THE TAX REVENUES OF THE POLITICAL SUBDIVISIONS IN WHICH ANY OF THE STRUCTURES, FACILITIES OR EQUIPMENT OF EMPIRE IS LOCATED?

A. No. Empire will continue to be the owner of network and properties after the close of the transaction and all of Empire's structures, facilities and equipment will remain in place upon closing. Thus, there is no impact upon the tax base in any of the political subdivisions.

Q. WILL THE TRANSACTION HAVE ANY EFFECT ON THE COMMISSION'S AUTHORITY TO REGULATE EMPIRE'S OPERATIONS?

A. No. The Commission's jurisdiction over Empire will not be reduced or impaired. The Commission will retain full regulatory supervision of Empire after the transaction is completed. In addition, the transaction will not restrict the Commission's access to Empire's books and records as is reasonably necessary to carry out the Commission's responsibilities with respect to Empire's operations, including proper audits.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes it does.

AFFIDAVIT OF BRAD P. BEECHER

STATE OF MISSOURI)
) ss
COUNTY OF JASPER)

On the 14th day of March, 2016, before me appeared Brad P. Beecher, to me personally known, who, being by me first duly sworn, states that he is the President and CEO of The Empire District Electric Company and acknowledged that he has read the above and foregoing document and believes that the statements therein are true and correct to the best of his information, knowledge and belief.

Brad P. Beecher

Brad P. Beecher

Subscribed and sworn to before me this 14th day of March, 2016

ANGELA M. CLOVEN
Notary Public - Notary Seal
State of Missouri
Commissioned for Jasper County
My Commission Expires: November 01, 2019
Commission Number: 15262659

Angela M. Cloven

Notary Public

My commission expires: 11/01/19.

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DIRECT TESTIMONY OF PETER EICHLER

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Peter Eichler. My business address is 354 Davis Road, Oakville, Ontario Canada L6J 2X1.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Liberty Utilities (Canada) Corp. ("Liberty Utilities Canada"), which is the parent company for Liberty Utilities Co. ("Liberty Utilities"), a Delaware corporation. Liberty Utilities is a holding company that owns corporations, which own and operate regulated gas, water, sewer and electric utilities in eleven states-Arizona, Arkansas, California, Iowa, Illinois, Missouri, Georgia, Massachusetts, Montana, New Hampshire and Texas. I am employed as Vice President of Strategic Planning. Liberty Utilities is the parent of Liberty Utilities (Central) Co. ("LU Central"), the organization formed to complete the acquisition of the shares of The Empire District Electric Company ("Empire"). LU Central will be a holding company and it is expected that all of the shares of the Liberty Utilities' subsidiaries, which own and operate regulated utility operations in the central and mid-western United States, will ultimately be transferred to LU Central.

Q. PLEASE DESCRIBE YOUR DUTIES AND RESPONSIBILITIES AS VICE PRESIDENT OF STRATEGIC PLANNING.

A. My responsibilities include oversight for Regulatory Strategy, Customer Experience Strategy, and Operations Strategy. As part of my role, I regularly evaluate the regulatory environments within which Liberty Utilities' businesses operate and provide advice to Liberty Utilities' management teams about investment decisions.

Q. HAVE YOU HELD OTHER POSITIONS WITH LIBERTY UTILITIES?

A. Yes. I was previously Manager of Financial Planning & Analysis. In that role I was in charge of financial planning, including ensuring overall accountability for rate cases. I was also responsible for analyzing regulatory related accounting and finance issues and responding to related discovery issues. I have also held the positions of Director of Regulatory Strategy, in which my responsibilities included crafting strategies to enhance relationships with state regulatory agencies and developing mechanisms by which customers and utility owners alike can benefit. I have also been involved in the management of certain unregulated affiliates of Liberty Utilities focused on providing hot water heater rentals, rooftop solar leases, and compressed natural gas initiatives.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. Before joining Liberty Utilities, I spent four years at regulated electric utilities in Ontario, Canada, working in the areas of Corporate Finance, Ratemaking and Regulatory Affairs. I am a designated accountant, having received the Certified Management Accountant (CMA) designation in Canada, which is now referred to as a Chartered Professional Accountant ("CPA, CMA"). That designation is similar to a Certified Public Accountant designation in the United States. In addition, I have completed a Masters of Business Administration degree from the University of Windsor in Ontario, Canada, and I have a Bachelor of Commerce degree with a specialization in Finance from Ryerson University in Toronto, Canada.

Q. DO YOU HAVE ANY SPECIALIZED TRAINING RELATED TO UTILITY RATEMAKING?

A. In addition to my work experience, I completed NARUC's Utility School in November 2009.

Q. HAVE YOU TESTIFIED BEFORE THE KANSAS CORPORATION COMMISSION ("COMMISSION") OR OTHER STATE PUBLIC UTILITY REGULATORY COMMISSIONS?

A. While I have not testified before the Kansas Commission, I have testified previously before many other commissions. Please see Exhibit PE-1 for a complete list of prior testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to discuss four matters associated with the proposed acquisition by LU Central of all of Empire's capital stock. I will describe the principal legal entities involved directly in the transaction, financing for the transaction, the financial strength of Liberty Utilities post-closing and the implications of the transaction as they may bear on affiliate transactions and corporate cost allocations. I will also explain how these matters inform the Commission's consideration of the question of whether the proposed transaction is in the public interest.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring Exhibit PE-2 which shows some of the estimated savings in regulated administration costs of the combined entities.

II. The Transaction

Q. PLEASE SUMMARIZE THE PROPOSED TRANSACTION THAT WILL CULMINATE IN THE ACQUISITION BY LU CENTRAL OF THE STOCK OF EMPIRE.

A. LU Central witness David Pasieka will address in more detail the features of, and rationale for, the acquisition of Empire. Generally, however, LU Central, which is a Delaware Corporation and a subsidiary of Liberty Utilities, proposes to acquire all of Empire's capital stock in an all-cash transaction through a merger of a wholly owned subsidiary, Liberty Utilities Sub Corp. ("LSC") and Empire. After the completion of the merger, LSC will cease to exist and LU Central will be the immediate parent of Empire. Empire's shareholders will receive $34 per common share. Additionally, Empire will maintain $900 million dollars of debt currently on its balance sheet for a total purchase price of $2.4 billion dollars. At the close of the transaction, Empire will become a wholly-owned subsidiary of LU Central.

Q. WILL EMPIRE'S STOCK CONTINUE TO BE TRADED ON THE NEW YORK STOCK EXCHANGE?

A. No. Following closing of the transaction, Empire will cease to be a publicly traded corporation under the new corporate structure. All of its shares of common equity will be held by LU Central.

Q. WHAT WILL BECOME OF THE REGULATED AND OTHER OPERATIONS OF EMPIRE?

A. Following the completion of the acquisition of the shares of Empire, all of Empire's assets utilized for the provision of electric, water and natural gas utility operations, as well as its fiber optic line of business, will continue to be owned by Empire and these services will continue to be provided by Empire and its existing subsidiary companies, The Empire District Gas Company ("EDG") and Empire District Industries ("EDI").

III. FINANCIAL CONDITION OF LIBERTY AFTER CLOSING

Q. WHAT IMPACT DO YOU ANTICIPATE THE TRANSACTION TO HAVE ON LIBERTY UTILITIES?

A. The transaction is expected to significantly strengthen Liberty Utilities' financial profile by creating a consolidated entity with combined utility rate base of approximately $2.9 billion serving nearly 800,000 gas, electric and water customers. Nearly 100% of Liberty Utilities' income will be earned from regulated utility operations. All of these factors are expected to contribute to continued strength in Liberty Utilities' investment grade credit rating, financial profile, and overall business operating environment.

Q. HOW DOES LIBERTY UTILITIES' INVESTMENT GRADE CREDIT RATING RELATE TO EMPIRE?

A. Under our operating model, all debt for regulated utilities is raised at the Liberty Utilities level. This debt is then mirrored to the individual regulated utility for which it is required. While Empire will maintain the debt currently on its books, future financing is expected to occur at the Liberty Utilities level and will be mirrored to Empire. For this reason, strength in Liberty Utilities credit rating will provide prudent access to capital.

Q. WHAT IMPACT WILL THE TRANSACTION HAVE ON THE CREDIT RATING OF

LIBERTY UTILITIES?

A. The financing plan for the acquisition of the shares of Empire is designed to maintain a strong investment grade rating. Based on discussions with Standard & Poor's undertaken prior to announcement of the Empire transaction, we do not anticipate any changes to Liberty Utilities' current BBB credit rating and believe that the Empire acquisition will be supportive of maintaining the rating.

IV. TRANSACTION RELATED FINANCING

Q. WHAT IS THE OVERALL VALUE OF THE TRANSACTION TO LIBERTY UTILITIES?

A. $2.4 billion in US dollars.

Q. FROM WHERE WILL THE CASH CONSIDERATION TO EMPIRE'S SHAREHOLDERS COME?

A. The total cash consideration required to purchase the shares of Empire from its shareholders is approximately $1.6 billion. Such amount shall be funded by a combination of equity sourced by Liberty Utilities' ultimate parent, Algonquin Power & Utilities Corp. ("Algonquin") and debt sourced by Liberty Utilities and contributed to LU Central to complete the acquisition of the Empire shares.

Q. HOW DOES LIBERTY UTILITIES SOURCE EQUITY FINANCING?

A. Liberty Utilities is the subsidiary of Algonquin, which is a publicly traded company on the Toronto Stock Exchange. Algonquin enjoys robust access to the capital markets and regularly raises equity that it in turn invests in its subsidiaries. Algonquin intends to raise the equity necessary to complete the transaction.

Q. HOW DOES LIBERTY UTILITIES SOURCE DEBT FINANCING?

A. Under our operating model, all debt for regulated utilities is raised at the Liberty Utilities level. Specific amounts of this debt are then mirrored to the individual regulated utility for which it is required. There is no cross collateralization, cross default or debt guarantees between the individual regulated utilities. While Empire will maintain the debt which is currently on its books, future financing is expected to occur at the Liberty Utilities level and then only that portion required by Empire will be mirrored to Empire. For this reason, the strength in Liberty Utilities credit rating will provide prudent access to capital.

Q. HOW IS THE PERMANENT FINANCING ASSOCIATED WITH THE TRANSACTION GOING TO BE STRUCTURED?

A. Permanent financing in the approximate amount of $ 2.4 billion for the acquisition of Empire is expected to be comprised of $0.9 billion in debt currently on the books of Empire and approximately $1.5 billion in debt obtained by Liberty Utilities and equity obtained by Algonquin and subsequently invested in Liberty Utilities. Contemporaneously with the announcement of the Empire transaction, Algonquin completed a $ 0.8 billion equity issuance in the form of mandatorily convertible debentures. The timing of additional debt and equity financing activities by Algonquin and Liberty Utilities will be influenced by the regulatory approvals process and is subject to prevailing market conditions.

Q. YOU MENTIONED THE MANDATORILY CONVERTIBLE DEBENTURE ISSUANCE HAS ALREADY BEEN COMPLETED. PLEASE ELABORATE.

A. On March 2, 2016, an offering by Algonquin of mandatorily convertible debentures was successfully completed. Demand in the capital markets for the securities comprising the offering was robust signaling a high level of enthusiasm for the Empire transaction.

Q. WILL LU CENTRAL HAVE ON-GOING ACCESS TO SUFFICIENT REASONABLY PRICED CAPITAL TO BE CONTRIBUTED TO ITS OPERATING SUBSIDIARIES?

A. Yes. Liberty Utilities and LU Central plan to use a reasonable and prudent investment grade capital structure comprised, initially of 55% equity and 45% debt. LU Central will be provided with appropriate amounts of debt and equity from Liberty Utilities to maintain such a capital structure. As discussed above Algonquin and Liberty Utilities both enjoy ready access to the public capital markets and have been able to source any required funding on reasonable terms. LU Central will, in turn, use the capital provided by Liberty Utilities to contribute the necessary capital to its utility subsidiaries, including Empire.

Q. HOW DOES THE PROPOSED DEBT TO EQUITY RATIO COMPARE TO EMPIRE'S CURRENT RATIO?

A. LU Central's debt to equity ratio contains slightly more equity than Empire's debt to equity ratio. This higher level of equity is intended to demonstrate Algonquin and Liberty Utilities' commitment to the Empire transaction and its intention to readily provide capitalization to the utility in the form of equity. Liberty Utilities and Empire are not seeking any approval of this higher level of equity for ratemaking purposes and intend to propose an appropriate capital structure for approval in the context of future rate cases. As such, the additional equity investment should be seen only for what it is; a demonstration of enthusiasm and commitment, and not a request for any increase to rates.

Q. IS THE COMPANY EXPECTING THE COMMISSION TO APPROVE THE CAPITAL STRUCTURES OF LU CENTRAL OR EMPIRE AS PART OF THIS

DOCKET?

A. No. As discussed above, LU Central expects that the appropriate capital structure along with associated components like return on equity and return on debt will be determined in a post-acquisition rate case.

Q. DOES THE PURCHASE PRICE TO BE PAID FOR EMPIRE REPRESENT A PREMIUM OVER THE MARKET PRICE FOR SHARES OF COMMON STOCK?

A. Yes. The price of $34 per common share represents a 21% premium to the closing price of Empire's stock on February 8, 2016.

Q. DOES LU CENTRAL INTEND TO SEEK RECOVERY IN RATES OF ANY OF THE PREMIUM PAID OVER MARKET TO ACQUIRE THE COMMON SHARES OF EMPIRE?

A. No. Neither LU Central nor Empire will in any future rate proceedings seek to recover any of the premium over the net book value of the assets associated with LU Central's acquisition of Empire's common shares. This topic is further discussed in the testimony of LU Central witness Christopher Krygier.

Q. HOW WILL LU CENTRAL ACCOUNT FOR THE PREMIUM?

A. At the time of closing, the acquisition premium will be accounted for as goodwill in the accounting records of LU Central.

Q. WILL LU CENTRAL'S COMMITMENT NOT TO SEEK RECOVERY IN RATES OF THE PREMIUM PAID IN THE ACQUISITION OF EMPIRE SHARES IMPAIR LU CENTRAL'S ABILITY TO FUND ITS SUBSIDIARY KANSAS UTILITY OPERATIONS OR DEGRADE ITS FINANCIAL CONDITION OF GOING

FORWARD?

A. Absolutely not. Liberty Utilities has a history of successfully acquiring utilities and, in each case, has ensured that such utilities were provided with on-going access to attractively priced capital following the acquisition. It would be antithetical to Liberty Utilities' operating philosophy to prevent its utilities from accessing the necessary capital and other resources required to prudently operate the utilities it owns. Further, Liberty Utilities' long history of successful acquisitions, the robust capital market demand for the recent equity issuance by Algonquin related to the Empire transaction and continued investment grade credit ratings gives confidence that it will be "business as usual" for all Liberty Utilities' subsidiary operations, both before and after the acquisition of Empire.

V. CORPORATE COST ALLOCATIONS AND AFFILIATE TRANSACTIONS

Q. PLEASE DISCUSS GENERALLY THE PROCESS LIBERTY UTILITIES USES TO ALLOCATE COSTS.

A. Liberty Utilities and its subsidiaries operate under a shared services model pursuant to which certain services are provided to the operating businesses from affiliates and charged to these utilities based on either a direct charge or defined cost allocation methodology (which methodology is structured pursuant to guidelines set by the National Association of Regulated Utility Commissioners). The majority of operating costs incurred by Liberty Utilities' regulated utilities are direct charges since such costs can be directly attributed to a particular business. In the case of labor costs, time sheets are maintained by all employees and the costs for each employee are charged to the business to which such employee is providing services. By utilizing direct charges whenever feasible, the shared services model has a significant level of transparency and simplicity that enables regulators to readily determine the costs attributable to parent level or affiliate services and whether those costs are appropriate. Costs that cannot be specifically attributed to a particular utility business are allocated across all businesses in proportions determined by a defined cost allocation methodology (again, based on guidelines set by the National Association of Regulated Utility Commissioners).

Q. CAN YOU PROVIDE A HIGH LEVEL OVERVIEW OF WHAT COSTS WILL BE ALLOCATED?

A. Yes. The cost allocations can be categorized into three distinct areas:

- Corporate Costs - These costs relate to the strategic management, capital markets costs, financial control costs, and head office administrative (rent, general office costs, etc.) which benefit all of Algonquin's subsidiaries including Liberty Utilities business. These costs are allocated based on a formulaic methodology that considers Net Plant, Number of Employees, Revenue and other factors depending on the type of cost.
- Business Services Costs - These costs relate to the overall administration of the business including regulated utilities owned by Liberty Utilities and are charged to the various Liberty Utilities subsidiaries using (a) direct charges or (b) allocated charges using a formulaic model. Business Services Costs include: labor for services such as accounting, administration, corporate finance, human resources, information technology, rates and regulatory affairs, environment health, safety, and security, customer service, procurement, risk management, legal and utility planning. The allocation methodology is similar to Corporate Costs, a driver based methodology that focuses on factors such as employees, square footage, capital expenditures and revenue

among others.

- Labor Charges: Liberty Utilities Service Corp. is the legal employer of all U.S. based utility employees. The costs of these employees are charged to each of the operating utilities based on time sheets. As an example, Mr. Krygier charges the vast majority of his time to Missouri, Iowa or Illinois utilities and there are only charges made to other utilities based on his time sheet entries reflecting support for a specific project. Costs other than labor based time sheet costs are allocated to the various Liberty Utilities subsidiary businesses based on a formulaic allocation methodology similar to that used for allocating Corporate Costs and Business Services Costs.

Q. WILL THE EMPIRE ACQUISITION RESULT IN ANY REDUNDANT LABOR OR DUPLICATION OF EFFORTS?

A. No. As discussed in the testimony of David Pasieka, we are currently beginning the transition planning process; however, one primary goal and objective is to ensure that there is no duplication of functions across Algonquin, Liberty Utilities, LU Central or each of the individual regulated utilities including Empire. Under the Liberty Utilities model, Empire will be charged for its fair share of the costs incurred by Algonquin, Liberty Utilities and LU Central. The structure of where services are performed (Algonquin, Liberty Utilities or regional entities such as LU Central) is still being determined but there will be no duplication of efforts.

Q. OVERALL, DO YOU ANTICIPATE THAT THE COMBINATION OF CORPORATE COSTS, BUSINESS SERVICES COSTS AND LABOR COSTS ATTRIBUTED TO EMPIRE FOLLOWING THE TRANSACTION WILL BE LESS THAN THE COSTS

CURRENTLY INCURRED BY EMPIRE TODAY?

A. Yes.

Q. PLEASE EXPLAIN.

A. There are several reasons why the costs borne by Empire will be lower under the Liberty Utilities allocation methodology. The reasons include:

1) As discussed previously, one of the prevailing strategic rationales for the transaction is gaining efficacy of scale. In LU Central, there will be approximately 120,000 more customers than Empire serves today, allowing for the distribution of costs over a larger number of customers.

2) Certain costs will be saved by the business combination, such as the costs Empire currently incurs to remain a public reporting issuer. We anticipate there are approximately $2.3 million in costs saved by not requiring Empire to comply with all the requirements of being a public reporting issuer.

3) While there will be no involuntary job losses within the Empire group, it is anticipated that, through natural attrition, an additional $2.2 million in labor savings will emerge. This is supported by Empire's 2-6% rate of annual attrition through employee turnover and retirements.

When reflected in the Liberty Utilities allocation model, these savings are expected to reduce the total costs borne by Empire's ratepayers.

Q. HOW MUCH IS THE SAVINGS EXPECTED TO BE?

A. Administration cost to serve Empire's customers are estimated to be reduced by $704,000, a decrease of 1.4%. Of this decrease, approximately $35,000 is attributable to Kansas customers.

Please see Exhibit PE-2. The reduced levels of allocations will be reflected in future rate cases.

Q. HAS THE COST ALLOCATION METHODOLOGY UTILIZED BY LIBERTY UTILITIES BEEN PREVIOUSLY FILED WITH THE COMMISSION?

A. No.

Q. WILL A REVISED CAM BE FILED WITH THE COMMISSION TO REFLECT THE EMPIRE TRANSACTION?

A. Yes, the Company will provide the revised CAM within six months of closing the Empire transaction.

Q. WHAT WILL BE DONE BY EMPIRE AND LU CENTRAL WITH REGARD TO THE COMMISSION'S SUPERVISION OF AFFILIATE TRANSACTIONS?

A. The utility business operated by Empire will continue to be under the direct regulation of the Commission. LU Central will commit to comply with the Commission's affiliated transactions and cost allocation statutes, rules and orders, by keeping such records and making such reports as are required by those statutes, rules and orders. Moreover, LU Central shall make records of its affiliated entities available to the Commission's staff and the Citizens' Utility Ratepayer Board ("CURB") for review.

Q. WHAT STEPS WILL BE TAKEN TO INSULATE EMPIRE FROM THE FINANCIAL RISKS ASSOCIATED WITH LIBERTY UTILITIES AND THE BUSINESSES OF ITS OTHER SUBSIDIARIES.

A. The businesses undertaken by Liberty Utilities are 'ring-fenced' separately and each operating entity is solely and only responsible for that portion of Liberty Utilities' debt specifically related to such business. As a result, there is no cross subsidization, cross collateralization between any business, regulated or unregulated.

VI. Public Interest Considerations

Q. DO YOU BELIEVE THAT THE PROPOSED TRANSACTION WILL BE PROMOTE THE PUBLIC INTEREST BASED ON THE COMMISSION'S EIGHT FACTOR TEST?

A. Yes. I believe the transaction will be beneficial to Empire's customers. From a purely financial perspective, Empire will become a part of a larger and more diversified utility business group. Empire will have the support of a larger balance sheet to meet the capital demands of its customers and it will benefit from the diversification of risk resulting from the geographic breadth of its North American operations. LU Central witnesses David Pasieka and Christopher Krygier will address other features and consequences of the proposed transaction that will demonstrate that it promotes the public interest .

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

VERIFICATION

PROVINCE ONTRAIO)
) ss:
CANADA)

I, Peter Eichler, being first duly sworn on oath, depose and state that I am the witness identified in the foregoing Direct Testimony of Peter Eichler; that I have read the testimony and am familiar with its contents; and that the facts set forth therein are true and correct.

SUBSCRIBED AND SWORN to before me this 16 day of March, 2016.

Notary Public

Commission/Appointment Expires: Does not expire

DANIELLE ELAN WILLOWAR NOTARY PUBLIC

Eichler - Regulatory Testimony History

	Docket Type	Description	Year	Jurisdiction	Subject Matter Supported	Docket Number
1	Rate Case	In the matter of Rio Rico Utilities Inc. request for increase in rates	2009	Arizona Corporation Commission	Corporate allocations, accounting and tax matters, organizational structure, compliance	WS-20676A-09
2	Rate Case	In the Matter of Bella Vista Company, Northern Sunrise, and Southern Sunrise Company Joint Application for Rate Increase	2009	Arizona Corporation Commission	Corporate allocations, accounting and tax matters, organizational structure, compliance	W-02465A-09
3	Rate Case	In the matter of Tall Timbers Utilities Inc. Application for Rate Increase	2010	Texas Commission on Environmental Quality	Rate Increase, Revenue Requirement, Revenue Allocation, Cost Allocations, Capital Expenditures, etc.	20694
4	Eminent Domain	In the matter of the City of Tyler v Tall Timbers Utilities	2010	Special Judicial Subcommittee of the Texas Commission on	Utility valuation, operations	N/A
5	Acquisition	Joint Petition of Liberty Utilities and National Grid to acquire Granite State Electric Co. and EnergyNorth Natural Gas Inc.	2011	New Hampshire Public Utilities Commission	Corporate philosophy, financing, rates and ratemaking, corporate allocations	DG 11-040
6	Acquisition	Request to acquire Atmos Energy's Illinois assets	2011	Illinois Corporation Commission	Corporate philosophy, financing, rates and ratemaking, corporate allocations	IL 11-0559
7	Acquisition	Request to acquire Atmos Energy's Iowa assets	2011	Iowa Utilities Board	Corporate philosophy, financing, rates and ratemaking, corporate allocations	SPU-2011-0008
8	Acquisition	Request to acquire Atmos Energy's Missouri assets	2011	Missouri Public Service Commission	Corporate philosophy, financing, rates and ratemaking, corporate allocations	GM-2012-0037
9	Rate Case	In the matter of California Pacific Electric Company request for Rate Increase	2012	California Public Utilities Commission	Corporate allocations, accounting and tax matters, organizational structure, compliance	A-12-02-014
10	Financing	Request to enter in to an intercompany loan arrangement	2012	Illinois Corporation Commission	Approval of financing, merger of entities	IL 12-0326
11	Rate Case	In the matter of Granite State Electric request for Rate Increase	2013	New Hampshire Public Utilities Commission	Corporate allocations, accounting and tax matters, organizational structure, compliance	DE 13-063
12	Acquisition	Request to acquire United Water Arkansas	2013	Arkansas Public Service Commission	Corporate philosophy, financing, rates and ratemaking, corporate allocations	12-061-U
13	Acquisition	Request to acquire Atmos Energy's Georgia assets	2013	Georgia Public Service Commission	Corporate philosophy, financing, rates and ratemaking, corporate allocations	DN 36278
14	Acquisition	Request to acquire New England Gas Co.	2013	Massechusetts Department of Public Utilities	Corporate philosophy, financing, rates and ratemaking, corporate allocations, tax matters	DPU 13-009

Exhibit PE-1

Docket Number:

Exhibit PE-2

Empire Net Savings				**2017**	**2018**	**2019**
Current EDE Allocations	USD		1	$ 52,105,155	$ 53,668,310	$ 55,278,359
Less: Inter-Mid States Allocations post acquisition	USD		2	$ 40,667,940	$ 41,887,978	$ 43,144,618
Net: Business Services/Corporate Costs/Labor	CAD		3	$ 15,026,357	$ 15,762,728	$ 16,716,864
Conversion Rate			4	1.4	1.4	1.4
Allocs in USD	USD		3/4=5	$ 10,733,112	$ 11,259,091	$ 11,940,617
Net Benefit/(Detriment)	USD		1-2-5=6	$ 704,103	$ 521,240	$ 193,124
EDE 4 Factor:						
Electric		91%		$ 640,781	$ 474,364	$ 175,756
Water		1%		$ 7,551	$ 5,590	$ 2,071
Gas		8%		$ 55,770	$ 41,286	$ 15,297
EDE 4 Factor Subtotal:		100%		$ 704,103	$ 521,240	$ 193,124
Check				$ -	$ -	$ -
EDE Electric Jurisdictional:						
Missouri		86.90%		$ 556,839	$ 412,222	$ 152,732
Kansas		5.53%		$ 35,435	$ 26,232	$ 9,719
FERC		2.70%		$ 17,301	$ 12,808	$ 4,745
Arkansas		2.58%		$ 16,532	$ 12,239	$ 4,535
Oklahoma		2.29%		$ 14,674	$ 10,863	$ 4,025
EDE Electric Jurisdictional Subtotal:		100.00%		$ 640,781	$ 474,364	$ 175,756

20160316155958
Filed Date: 03/16/2016
State Corporation Commission
of Kansas

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Joint Application of The Empire District Electric Company, Liberty Sub Corp. and Liberty Utilities (Central) Co. for Approval of an Agreement and Plan of Merger and for Other Related Relief	)))))	Docket No. 16-EPDE-_____-ACQ

DIRECT TESTIMONY OF CHRISTOPHER D. KRYGIER

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND BUSINESS AFFILIATION.

A. My name is Christopher D. Krygier, my business address is 2751 North High Street, Jackson, Missouri 63755. I am testifying on behalf of the applicants, Liberty Utilities (Central) Co. ("LU Central" or "Company") and Liberty Sub Corp ("LSC"), wholly owned subsidiaries of Liberty Utilities Co. ("Liberty Utilities").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. In 2006, I completed my Bachelor of Science in Economics from the W.P. Carey School of Business at Arizona State University. In 2010, I completed my Master of Business Administration with an emphasis in Finance also from Arizona State University. Finally, I am a Certified Management Accountant as designated by the Institute of Management Accountants.

I am employed by Liberty Utilities Services Corp. as its Director of Regulatory and Government Affairs for its natural gas, water and wastewater utilities in Missouri, Iowa and

Illinois. I have been employed with Liberty Utilities since March 2012. Before working for Liberty Utilities, I was employed by American Water Works, Inc. for approximately six years in a variety of capacities, including Financial Planning and Analysis, Rates, Regulatory Compliance and Capital Programs.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KANSAS CORPORATION COMMISSION ("COMMISSION")?

A. No, I have filed testimony in Missouri, provided written and live testimony before the Arizona Corporation Commission, written testimony before the Hawaii Public Utilities Commission and the Illinois Commerce Commission.

II. <u>Purpose of Testimony</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS CASE?

A. The purpose of my testimony is to address certain aspects of this Commission's regulatory responsibilities regarding the proposed transaction between LU Central and The Empire District Electric Company ("Empire"), to provide some background regarding Liberty Utilities existing regulated utility operations in neighboring states and to discuss key features of the proposed transaction that should be considered by the Commission as it reviews the Joint Application, including the benefits of the transaction for customers.

III. <u>Commission Jurisdiction and Standard of Approval</u>

Q. ARE YOU FAMILIAR WITH THE TRANSACTION THAT IS THE SUBJECT OF THE JOINT APPLICATION FILED BY THE JOINT APPLICANTS IN THIS CASE?

A. Yes. Specifics of the transaction will be addressed in more detail by Company witnesses David Pasieka and Peter Eichler; but, generally, LU Central has entered into an Agreement and

Plan of Merger whereby LU Central will acquire all of the capital stock of Empire through a merger of LSC and Empire. After the merger, LSC will cease to exist. At the close of the all-cash transaction, Empire will become a wholly-owned subsidiary of LU Central and Empire will continue to be regulated by this Commission. Mr. Pasieka's testimony includes an organization chart that depicts the relationship among LU Central and Empire.

Q. WHAT IS THE BASIS OF THE COMMISSION'S JURISDICTION OVER THE PROPOSED TRANSACTION?

A. My understanding is that the Commission has the authority to review and approve the proposed transaction because the acquisition by LU Central of the capital stock of Empire involves a merger of Empire and another corporation, LSC which has been formed for the sole purpose of this transaction.

Q. ARE YOU FAMILIAR WITH THE STANDARD FOR APPROVAL OF THE PROPOSED TRANSACTION?

A. It is my understanding that applicants seeking approval of a utility merger or acquisition in Kansas must show that the acquisition will "promote the public interest" based on the Commission's consideration of eight factors.

Q. DOES THE TRANSACTION DESCRIBED IN THE JOINT APPLICATION AND IN THE TESTIMONY OF THE SUPPORTING WITNESSES SATISFY THIS STANDARD?

A. Yes it does. As explained further below, the transaction will promote the public interest in a number of ways.

IV. Liberty Utilities' Operations in Neighboring States

Q. PLEASE PROVIDE THE COMMISSION WITH INFORMATION ON EXISTING LIBERTY UTILITIES' OPERATIONS IN NEIGHBORING STATES.

A. Liberty Utilities (Midstates Natural Gas) Corp. provides natural gas services to an average of approximately 55,000 customers in its West, Northeast, and Southeast service territories in Missouri, which includes Pemiscot, Dunklin, New Madrid, Bates, Iron, Cape Girardeau, Clark, Adair, Know, Lewis, Schuyler, Macon, Scotland, Henry, Stoddard, Ripley, Butler, Wayne, and Marion Counties. Liberty Utilities (Missouri Water), LLC provides water service to approximately 1,994 connections in Jefferson, Stone, Taney, McDonald, and Franklin Counties, Missouri. Liberty Utilities provides sewer service to approximately 451 connections in Jefferson, Stone, and Cape Girardeau Counties, Missouri. Liberty Utilities (Pine Bluff Water), Inc. provides water and wastewater services to 17,000 customers in Pine Bluff, Arkansas. Liberty Utilities has offices in Jackson, Missouri and Pine Bluff, Arkansas, with approximately 85 employees in these locations. The company has successfully operated these utilities since their acquisition. In that time, the company has demonstrated that it has the managerial, operational and financial wherewithal to provide safe, affordable and reliable service to its customers, all in compliance with applicable rules and regulations of the regulatory commissions which have jurisdiction over its operations. We believe we have developed a positive, constructive relationship with our state regulators, and are proud of the successes of our Missouri and Arkansas businesses and in the positive experience those successes have meant for our customers.

V. <u>BENEFITS OF THE TRANSACTION</u>

Q. DO YOU BELIEVE THAT THE PROPOSED TRANSACTION WILL PROVIDE

BENEFITS TO THE CUSTOMERS OF EMPIRE?

A. Yes. I believe that the proposed transaction will positively benefit Empire's customers in Kansas.

Q. PLEASE EXPLAIN THE BENEFITS OF THE TRANSACTION.

A. This transaction has many benefits, which include:

1) Efficacy of scale - This transaction represents an opportunity to increase the size of the respective organizations to nearly 800,000 combined customers providing service across 13 states with expertise in water, gas, and electric distribution utilities. This scale is expected to result in greater management expertise, access to broader management capabilities, and an ability to capitalize on greater opportunities for future efficiencies.

2) Increased Management Capability - By combining the expertise of both companies, a joint entity will now enjoy expertise in:

   a. Electric utility operations of over 270,000 customers including vertical integration with utility owned and developed renewable energy and conventional generation fleet.

   b. Gas utility operations of over 330,000 customers with expertise in the development of distribution utility best practices, service territory expansion, alternate fuel procurement, and investment in gas transmission infrastructure.

   c. Distribution utility expertise of running large water operations in excess of 175,000 customers, including in drought prone areas.

   d. Access to renewable energy development expertise that has already proven to be beneficial to Liberty's electric utilities it owns in other jurisdictions with investments in utility owned solar generation that is expected to reduce overall customer energy costs.

3) Enhanced regional senior leadership support - By reorganizing Liberty Utilities' operations under East, Central, and West regional divisions, each utility will now have closer access to senior level leadership. Through the Empire acquisition, Liberty's operations in Missouri, Arkansas, Illinois, Iowa, and Texas will now have access to the diverse and talented management team based in Joplin, Missouri. This means that senior management of the utilities will be even closer to the service territory, ensuring responsiveness to the local community and expeditious responsiveness to emerging issues within each community.

4) Board of Directors for LU Central - A regional board of directors will be established consisting of senior business and community leaders. This board is expected to provide governance and guidance on local issues to ensure that the combined entity will enhance its understanding of local operating conditions and be able to better serve the needs of customers. The board will have commensurate fiduciary duties, and all existing board members of Empire will be offered a position on the board.

5) Enhanced financial capabilities - Combining the financial strength of two organizations with a BBB credit rating will ensure stronger access to financial markets and provide enhanced momentum to work towards enhancing the credit rating in the future by providing increased diversification of modality, geography, and ultimately further diversifying the risks of both organizations.

6) Maintains jobs - This transaction is not about cutting jobs. Rather, the rationale of the transaction is to enhance the capabilities of both organizations and as such, there will be no involuntary workforce reductions associated with this transaction.

7) Seamless transition - Over the last 5 years, Liberty Utilities has completed 7 major transitions that have been seamless from a customer perspective and has developed a core competence in merging utility operations in to its own. With the Empire transaction, this capability will be enhanced as the acquisition is of a fully functioning standalone utility operation which will allow optimal staging of transition activities.

These benefits are further explained in the testimony of David Pasieka.

Q. WHAT DOES BECOMING A PART OF LU CENTRAL MEAN FOR KANSAS CUSTOMERS?

A. Liberty Utilities' operations in Kansas will be enhanced by becoming a subsidiary of LU Central in several ways.. First, the acquisition allows for access to a senior management team with significant utility expertise in gas, water, and electric utility operations based closer to its operations in Joplin, Missouri. This closeness will allow for enhanced responsiveness and enhanced skillsets to respond to utility operating requirements. In addition, through a regional board, the management team in Missouri will have opportunities to receive guidance and counsel from local business and community leaders who can provide insight to the emerging issues within the service territory. Further, the efficacy of scale will allow these utilities to now be a part of a region with approximately 340,000 customers in a company with nearly 800,000 customers. This scale will allow future opportunities to capitalize on efficiencies as they emerge.

Q. YOU MENTIONED AN LU CENTRAL BOARD OF DIRECTORS, BUT STATE THAT EACH ENTITY WILL CONTINUE TO OPERATE SEPARATELY. CAN YOU RECONCILE THESE STATEMENTS?

A. Certainly. The LU Central board of directors will oversee each entity within the division.

Q. WILL THE PROPOSED ACQUISITION RESULT IN ANY ADVERSE RATE IMPACTS ON EMPIRE'S RETAIL CUSTOMERS?

A. No. The proposed transaction will not result in any change in the rates currently charged to Empire's retail customers. Empire will continue to utilize the rates, rules, regulations and other tariff provisions on file with and approved by the Commission, and will continue to provide service to their customers under those rates, rules and regulations, and other tariff provisions until such time as they may be modified according to applicable law. Further, as I discuss later in my testimony, LU Central hereby commits not to seek any merger related adjustments for acquisition costs or any premiums paid above book value.

Q. WHAT ABOUT ONGOING REGULATORY CONDITIONS OR COMMITMENTS TO WHICH EMPIRE MAY BE SUBJECT?

A. Empire will continue to comply with any ongoing regulatory commitments that are currently in place with respect to its electric operations. I discuss the specifics below.

Q. DOES LU CENTRAL INTEND TO MAINTAIN EMPIRE'S PERFORMANCE REGARDING CUSTOMER SERVICE?

A. Yes. There will be no change to Empire's customer service standards or to its excellent customer service record. The fact that Empire's customer service staff will be retained, as discussed below, should provide assurance of a seamless transition where customer service is concerned. I will address Liberty Utilities' customer service philosophy and how well it dovetails with that of Empire below.

Q. IS LIBERTY UTILITIES ABLE TO MAKE ANY OTHER OR ADDITIONAL COMMITMENTS TO SHOW THE COMMISSION THAT THE PROPOSED TRANSACTION WILL BENEFIT CUSTOMERS OF EMPIRE?

A. Yes. The Company plans to keep all of Empire's employees, including the management team and those handling field and customer service operations, so there will be no disruption whatsoever in the continued provision of good service to the customers of Empire. The Merger Agreement also provides certain protections to current Empire employees regarding their pay and benefits after the closing of the transaction.

Q. WHAT ABOUT THE LONG-TERM IMPACT OF THE PROPOSED TRANSACTION ON ACCESS TO CAPITAL MARKETS?

A. Company witness Peter Eichler testifies that LU Central will have ready access to capital at a reasonable cost through the corporate structure and will maintain a strong balance sheet. Liberty Utilities also anticipates attracting debt or equity capital to meet the ongoing needs of Empire at rates at least as favorable as they are attained today. With the increased economies of scale of the combined entities and maintenance of investment grade credit ratings, we expect long term costs of borrowing to be at least the same if not more competitive than on a standalone basis.

Q. IS THERE NOT A NEW OR INCREASED RISK OF INAPPROPRIATE AFFILIATE TRANSACTIONS IF EMPIRE BECOMES A SUBSIDIARY OPERATING COMPANY IN A LARGER HOLDING COMPANY STRUCTURE?

A. No. Mr. Eichler also testifies to the fact that the Company already has in place a cost allocation manual that sets forth a cost allocation methodology to be used by all regulated utility entities, based largely on the guidelines established by National Association of Regulatory Utility Commissioners. Liberty Utilities will revise or modify its current cost allocation manual, as needed, to reflect the acquisition of Empire within six (6) months following the closing of the transaction.

Q. ARE THERE ANY OTHER MATTERS THE COMMISSION SHOULD CONSIDER REGARDING THE PUBLIC INTEREST?

A. The Company believes that the Commission also should take into account the local impact of the proposed transaction when it considers the public interest. We believe that it is significant that the Company plans to retain Empire's headquarters in Joplin, Missouri. Doing so is good for the local economy, the many surrounding communities, including those communities served by Empire in Southeast Kansas.. I will address the Company's commitment to continued community involvement below.

Q. DOES THE PURCHASE PRICE ANNOUNCED CONTAIN A PREMIUM OVER MARKET?

A. Yes. The purchase price of $34 per common share represents a 21% premium to the closing price of Empire's stock on February 8, 2016.

Q. DOES LU CENTRAL PROPOSE TO RECOVER ANY PART OF THE PREMIUM OVER BOOK VALUE IN THE RATES CHARGED TO EMPIRE?

A. No. The Company will not seek any recovery of the amount of the premium over book value or recovery of any acquisition premium relating to the net book value of the assets in Empire's rate base in future Empire rate cases.

Q. WILL ANY OF THE REGULATED ENTITIES SEEK TO RECOVER ANY TRANSACTION COSTS ASSOCIATED WITH THE PROPOSED TRANSACTION?

A. No. None of the Empire or Liberty Utilities regulated utilities will seek to recover in rates the transaction costs associated with the acquisition.

VI. <u>CUSTOMER SERVICE AND COMMITMENT TO COMMUNITY</u>

Q. WHAT IS LIBERTY UTILITIES' PHILOSOPHY REGARDING CUSTOMER SERVICE?

A. As mentioned by Mr. Pasieka in his testimony, Liberty Utilities focuses on providing high quality customer service. We achieve this by delivering our service in the utility service territory compared to outsourcing, distributing timely information to our customers in a medium they prefer and giving local management teams the authority and autonomy to best determine local customer needs.

Q. WILL THIS APPROACH CHANGE WITH THIS ACQUISITION?

A. Absolutely not. One of the important aspects of this acquisition is the shared customer service philosophy by Empire. While they don't always use the same words that Liberty Utilities does to describe customer service, it is clear through the successful results that being customer centric is integral to their success.

Q. WILL ANY EMPIRE PAYMENT CENTERS OR PAY STATIONS BE CLOSED BECAUSE OF THE ACQUISITION?

A. No. All pay stations that exist today will remain open after the acquisition.

Q. WILL THE COMPANY MAINTAIN EMPIRE'S CURRENT CONTACT CENTER

METRICS POST ACQUISITION?

A. Yes. Empire currently employs a number of customer contact center metrics including an average speed of answer, abandoned call rate, and average handle time, among others. None of these reporting metrics will change as a result of the acquisition.

Q. WILL EMPIRE'S COMMUNITY INVOLVEMENT IN JOPLIN OR SURROUNDING AREAS CHANGE AS PART OF THE TRANSACTION?

A. No. Empire's community commitment and involvement is a shared philosophy of LU Central. We are building on that shared philosophy by creating a regional board, which will provide guidance and counsel to ensure that the combined entity will enhance its understanding of local operating conditions and be able to better serve the needs of customers. Additionally, after the closing, LU Central has committed to the same level of charitable contributions through Empire as Empire currently does today.

Q. WILL CUSTOMER RELIABILITY BE IMPACTED BY THE TRANSACTION?

A. Customer reliability will be maintained through this transaction. As stated above, Empire management and employees are being retained as part of the transaction and therefore the engineering, operational and other expertise necessary to continue the provision of safe, reliable service is intact. Additionally, in order to strive to continuously improve customer reliability, the shared knowledge of both companies will be used to utilize best practices for Empire's customers, one of the many benefits of the transaction.

Q. DOES EMPIRE HAVE ANY ONGOING REGULATORY COMMITMENTS WITH RESPECT TO ITS EXISTING KANSAS OPERATIONS?

A. Yes, Empire has ongoing regulatory commitments relative to its Kansas operations.

Q. WILL THE PROPOSED TRANSACTION NECESSITATE ANY CHANGE TO THOSE COMMITMENTS?

A. No.

Q. WILL THE PROPOSED TRANSACTION REQUIRE ANY RELOCATION OF EMPIRE'S BOOKS AND RECORDS?

A. No.

Q. AS FAR AS RECORDS KEPT BY LU CENTRAL OR ITS VARIOUS SUBSIDIARIES CONCERNING EMPIRE'S OPERATIONS, PLEASE ADDRESS THE AVAILABILITY OF THOSE RECORDS FOR REVIEW BY THE COMMISSION OR ITS STAFF.

A. LU Central will ensure that appropriate access to Empire's books and records are provided to the Commission and its Staff.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

VERIFICATION

STATE OF MISSOURI)
) ss:
COUNTY OF Cape Girardeau)

I, Christopher D. Krygier, being first duly sworn on oath, depose and state that I am the witness identified in the foregoing Direct Testimony of Christopher D. Krygier; that I have read the testimony and am familiar with its contents; and that the facts set forth therein are true and correct.

ChrisKrygier 3/14/16

SUBSCRIBED AND SWORN to before me this 14th day of March, 2016.

Tiffany Shasserre
Notary Public

Commission/Appointment Expires: 5/6/2018

NOTARY PUBLIC STATE OF MISSOURI NOTARY SEAL

TIFFANY SHASSERRE
My Commission Expires
May 6, 2018
Cape Girardeau County
Commission #14613101

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Joint Application of The Empire District Electric Company, Liberty Sub Corp. and Liberty Utilities (Central) Co. for Approval of an Agreement and Plan of Merger and for Other Related Relief	)))))	Docket No. 16-EPDE-_____-ACQ

DIRECT TESTIMONY OF DAVID PASIEKA

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David Pasieka. My principal place of business is 354 Davis Road, Oakville, Ontario, Canada L6J 2X1.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR JOB TITLE?

A. I am President of Liberty Utilities (Canada) Corp., the holding company that owns Liberty Utilities Co. ("Liberty Utilities") and indirectly owns Liberty Utilities (Central) Co. ("LU Central") and Liberty Sub Corp. ("LSC").

Q. WHAT ARE YOUR RESPONSIBILITIES AS PRESIDENT OF LIBERTY UTILITIES (CANADA) CORP.?

A. As President, I am responsible for the overall strategy and direction of the regulated utilities owned by Liberty Utilities. These responsibilities include, among other things, overseeing Operations, Human Resources, Safety, Regulatory, Customer Service and Finance.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I earned a Bachelor of Science degree from the University of Waterloo in 1980, a Master of Business Administration from York University's Schulich School of Business in 1984, and a Chartered Director designation from McMaster University in 2007. My business experience includes more than 30 years of executive leadership in the telecommunications, financial services, energy, utility and sustainability sectors.

For the first 20 years of my career I was involved with the Canadian telecommunications sector, working for Bell Canada, CNPC Telecommunications, Unitel Communications, AT&T Canada, and MetroNet Communications. During the late 1990's and early 2000's, my career focused on early-stage start-ups and corporate turnarounds, working in the energy, sustainability, enterprise software, and innovation sectors.

I have significant experience in organization development, corporate integration, profit and loss management, customer service, strategy, information technology, business development, and network operations. My board of directors' experience consists of chairing the Audit Committee of Iseemedia (a Canadian wireless software company) from 2007-2010, chairing the Human Resources Committee of Luxell Technologies (a Canadian aerospace company) from 2005-2009, and chairing the Human Resources Committee of Oakville Hydro (a local electric distribution company) from 2008-2011.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KANSAS CORPORATION COMMISSION ("COMMISSION" OR "KCC") OR SIMILAR REGULATORY COMMISSIONS?

A. While I have not testified before this Commission, I have testified in Arkansas regarding Liberty Utilities' acquisition of United Water Arkansas, Inc.'s Pine Bluff system in 2013, and have filed written testimony in Missouri in 2012 regarding the Liberty Utilities' acquisition of the natural gas distribution assets of Atmos Energy Corp., and in New Hampshire on the acquisition of electric and natural gas distribution utilities from National Grid in 2012.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS CASE?

A. The purpose of my testimony is to (1) describe the proposed transaction and identify the parties involved, including a description of the corporate and operating structure of Liberty Utilities and how The Empire District Electric Company ("Empire") will fit into that structure post-merger; (2) describe Liberty Utilities' experience in the electric, gas, and water utility industries and its transition plans; (3) discuss Liberty Utilities' approach and commitment to providing high quality, cost-effective customer service, and (4) explain why the transaction meets the Commission's standard that utility acquisitions promote the public interest and result in a "net-benefit."

Q. ARE YOU SPONSORING ANY EXHIBITS OR SCHEDULES AS PART OF YOUR DIRECT TESTIMONY?

A. Yes. I am sponsoring the following exhibit attached to my testimony and an appendix attached to the Joint Application:

Appendix K to the Joint Application: An organizational chart showing where Empire would fit within the overall Liberty Utilities organization.

Exhibit DP-1: Liberty Utilities' 2015 customer satisfaction results.

II. THE PROPOSED TRANSACTION AND THE RATIONALE FOR IT

Q. PLEASE DESCRIBE THE TRANSACTION THE JOINT APPLICANTS ARE ASKING THE COMMISSION TO APPROVE IN THIS CASE.

A. The specific terms of the proposed transaction are set out in the February 9, 2016, "Agreement and Plan of Merger by and among The Empire District Electric Company, Liberty Utilities (Central) Co. and Liberty Sub Corp." ("Agreement"). A copy of the Agreement was filed as part of the Joint Application in this case. Under the Agreement, LU Central will acquire all issued and outstanding shares of Empire's stock and then merge Empire with LSC, a wholly-owned merger subsidiary of LU Central created solely for this transaction, with Empire emerging as the surviving corporation. Following the merger LSC will cease to exist and Empire will be a wholly-owned subsidiary of LU Central. An organizational chart showing where Empire would fit within the overall Liberty Utilities organization is attached as Appendix K to the Joint Application.

Q. PLEASE DESCRIBE HOW YOU INTEND TO OPERATE EMPIRE AND YOUR EXISTING UTILITY PORTFOLIO.

A. Our ultimate plan is for Empire and certain of Liberty Utilities' existing utilities to be reorganized under LU Central, with Bradley Beecher, the current CEO of Empire assuming the role of the CEO of LU Central. The entities to be within LU Central will be Empire District, Liberty Utilities natural gas utilities located in Missouri, Illinois and Iowa, and Liberty Utilities water utilities located in Arkansas, Missouri and Texas. Combined, approximately 340,000 customers will be served by LU Central.

As discussed further in my testimony, the management team of Empire will provide services to all the utilities within LU Central and shared services may be provided where appropriate and in accordance with affiliate transaction statutes, rules and Commission orders. Further, a board of directors with commensurate fiduciary duties consisting of senior business and community leaders will be established to provide guidance and counsel to the operations of the utilities within LU Central with the members of the current Empire board of directors being offered a position on the regional board.

Q. WILL THE UTILITIES MENTIONED ABOVE CONTINUE TO OPERATE ON A STANDALONE BASIS OR BE MERGED IN TO A SINGLE ENTITY?

A. The utilities will continue to operate on a standalone basis, with separate tariffs, assets, and books and records.

Q. WHAT IS THE PRIMARY RATIONALE BEHIND THE TRANSACTION?

A. This transaction has many benefits that will inure to the customers, employees, regulators, and shareholders of both Empire and Liberty Utilities. These benefits are:

1) Efficacy of scale - This transaction represents an opportunity to increase the size of the respective organizations to nearly 800,000 combined customers providing service across 13 states with expertise in water, gas, and electric distribution utilities. This scale is expected to result in greater management expertise, access to broader management capabilities, and an ability to capitalize on greater opportunities for future efficiencies.

2) Increased Management Capability - By combining the expertise of both companies, a joint entity will now enjoy expertise in:

   a. Electric utility operations of over 270,000 customers including vertical integration with utility owned and developed renewable energy and conventional generation fleet.

   b. Gas utility operations of over 330,000 customers with expertise in the development of distribution utility best practices, service territory expansion, alternate fuel procurement, and investment in gas transmission infrastructure.

c. Distribution utility expertise of running large water operations in excess of 175,000 customers, including in drought prone areas.

d. Access to renewable energy development expertise that has already proven to be beneficial to Liberty's electric utilities it owns in other jurisdictions with investments in utility owned solar generation that is expected to reduce overall customer energy costs.

3) Enhanced regional senior leadership support - By reorganizing Liberty Utilities' operations to include LU Central, each utility will now have access to senior level leadership. Liberty Utilities' operations in Missouri, Arkansas, Illinois, Iowa, and Texas will now have access to the diverse and talented management team based in Joplin, Missouri. This means that senior management of the utilities will be even closer to the service territory, ensuring responsiveness to the local community and expeditious responsiveness to emerging issues within each community.

4) Board of Directors for LU Central - A regional board of directors will be established consisting of senior business and community leaders. This board is expected to provide guidance and counsel on local issues to ensure that the combined entity will enhance its understanding of local operating conditions and be able to better serve the needs of customers. The board will have commensurate fiduciary duties, and all existing board members of Empire will be offered a position on the board.

5) Enhanced financial capabilities - Combining the financial strength of two

organizations with a BBB credit rating will ensure stronger access to financial markets and provide enhanced momentum to work towards enhancing the credit rating in the future by providing increased diversification of modality, geography, and ultimately further diversifying the risks of both organizations.

6) Maintains jobs - This transaction is not about cutting jobs. Rather, the rationale of the transaction is to enhance the capabilities of both organizations and as such, there will be no involuntary reductions associated with this transaction.

7) Seamless transition - Over the last 5 years, Liberty Utilities has completed 7 major transitions that have been seamless from a customer perspective and has developed a core competence in merging utility operations in to its own. With the Empire transaction, this capability will be enhanced as the acquisition is of a fully functioning standalone utility operation which will allow optimal staging of transition activities.

As can be seen, these items represent significant benefits of the transaction for customers, employees, regulators, and shareholders of both Empire and Liberty Utilities.

Q. IN YOUR PREVIOUS ANSWER, YOU POINTED TO NUMEROUS BENEFITS EMPIRE AND ITS CUSTOMERS WOULD DERIVE FROM THE PROPOSED TRANSACTION. ARE THERE ANY DETRIMENTS THE COMMISSION SHOULD CONSIDER IN EVALUATING THE TRANSACTION?

A. None of which I am aware. To the extent any detriments can be identified, I am confident they are nullified by commitments made in my testimony and the direct testimonies of Mr. Eichler and Mr. Krygier or are more than outweighed by the many beneficial aspects of the proposed transaction.

Q. DO THE OTHER STATE COMMISSIONS IN WHICH EMPIRE OPERATES APPLY DIFFERENT STANDARDS FOR CONSIDERATION OF UTILITY ACQUISITIONS?

A. Yes. Each state has its own approach. While Kansas applies a public interest standard, Missouri applies a "no net detriment standard," Arkansas applies a "consistent with public interest" standard, and Oklahoma applies a "public interest" standard. The proposed acquisition meets all of these tests, because as demonstrated above, there are many benefits associated with the transaction, which far outweigh any potential detriments.

Q. WHAT ARE THE NEXT STEPS BEFORE THE PROPOSED TRANSACTION CAN BE CONSUMMATED?

A. Although the boards of directors of Empire and LU Central already have approved the transaction, certain contingencies must be satisfied before it can be consummated. Empire's current shareholders must approve the transaction; Empire's board has recommended approval to its shareholders and a shareholder vote is planned for the summer of 2016. In addition, the Federal Energy Regulatory Commission and the utility regulatory commissions in each of the four states where Empire provides utility services -Kansas, Missouri, Arkansas, and Oklahoma - must each approve the transaction. Contemporaneous with the filing of this application, the joint applicants have filed for regulatory approval with each of these other commissions. Further, an application will be made with the Federal Trade Commission for approval under the Hart-Scott-Rodino Antitrust Improvements Act. As this approval expires 365 days after receipt, it will be sought shortly.

Q. WHEN DO YOU ANTICIPATE THAT THIS TRANSACTION WOULD CLOSE?

A. The joint applicants are seeking Commission approval by December 31, 2016 so that the transaction can close by January 31, 2017.

III. STANDARD OF APPROVAL

Q. ARE YOU FAMILIAR WITH THE LEGAL STANDARDS THAT GOVERN THE COMMISSION'S CONSIDERATION OF UTILITY ACQUISITIONS IN KANSAS?

A. My understanding is the legal standard applicable to utility acquisitions in Kansas is that the proposed acquisition should be approved where the applicants can demonstrate that the proposed acquisition will promote the public interest. In determining the public interest, the Commission considers the following factors:

a. The effect of the transaction on consumers, including:

   i. The effect of the proposed transaction on the financial condition of the newly created entity as compared to the financial condition of the stand-alone entities if did not occur;

   ii. Reasonableness of the purchase price, including whether the purchase price was reasonable in light of the savings that can be demonstrated from the merger and whether the purchase price is within a reasonable range;

   iii. Whether ratepayer benefits resulting from the transaction can be quantified;

   iv. Whether there are operational synergies that justify payment of a premium in excess of book value;

   v. The effect of the proposed transaction on the existing competition.

b. The effect of the transaction on the environment.

c. Whether the proposed transaction will be beneficial on an overall basis to state and local economies and to communities in the area served by the resulting public utility operations in the state.

d. Whether the proposed transaction will preserve the jurisdiction of the KCC and the capacity of the KCC to effectively regulate and audit public utility operations in the state.

e. The effect of the transaction on affected public utility shareholders.

f. Whether the transaction maximizes the use of Kansas energy resources.

g. Whether the transaction will reduce the possibility of economic waste.

h. What impact, if any, the transaction has on the public safety.

It is my understanding that the Commission utilizes this standard to "uniformly review mergers and acquisitions…while allowing some flexibility to evaluate the unique circumstances of each case." *In the Matter of Application of Kansas City Power and Light*, Order dated November 14, 1991, at pages 35-36. I will address each factor herein.

Q. YOU MENTIONED THAT THE COMMISSION STANDARD ALLOWS FOR FLEXIBILITY TO EVALUATE THE UNIQUE CIRCUMSTANCES OF EACH CASE. ARE THERE ANY UNIQUE CIRCUMSTANCES YOU WOULD LIKE TO MENTION?

A. In my testimony I lay out the rationale for the transaction. While the Commission's factors seem to emphasize financial benefits to customers, this transaction emphasizes a number of other benefits such as the efficacy of scale, local control and management, and opportunities to enhance the management team of a combined entity. The transaction is perhaps unique in that no major changes are currently planned. The management team will be preserved. The head office will remain in Joplin, and the same great service being provided to customers of Empire today is expected to be provided after closing. Empire, while joining the LU Central organization, will continue to remain a standalone entity and will not be merged in to any other entity in the Liberty Utilities family, and to that end, this transaction is not about creating synergies on account of staffing reductions or reductions in service. Rather, the benefits outlined in my testimony will inure to customers and enhance the current operations.

Q. IN THE COMMISSION'S FIRST FACTOR, PLEASE EXPLAIN THE EFFECT OF THE TRANSACTION ON CONSUMERS, INCLUDING ON THE FINANCIAL CONDITION OF THE NEWLY CREATED ENTITY COMPARED TO THE FINANCIAL CONDITION OF EMPIRE TODAY.

A. As Mr. Eichler explains, the financial condition of Empire is expected to be improved by joining together with Liberty Utilities. The transaction is expected to significantly strengthen its financial profile by creating a consolidated entity with combined utility rate base of approximately $2.9 billion serving nearly 800,000 gas, electric and water customers. Nearly 100% of Liberty Utilities' income will be earned from regulated utility operations. All of these factors are expected to contribute to continued strength in Empire's and Liberty Utilities' investment grade credit rating, financial profile, and overall business operating environment.

Q. HOW DOES LIBERTY UTILITIES' INVESTMENT GRADE CREDIT RATING RELATE TO EMPIRE?

A. As discussed in Mr. Eichler's testimony, under our operating model, all debt for regulated utilities is raised at the Liberty Utilities level. Specific amounts of this debt is then mirrored to the individual regulated utility for which it is required. There is no cross collateralization, cross default or debt guarantees between the individual regulated utilities. While Empire will maintain the debt which is currently on its books, future financing is expected to occur at the Liberty Utilities level and only that portion required by Empire will be mirrored to Empire. For this reason, the strength in Liberty Utilities credit rating will provide prudent access to capital.

Q. WHAT IMPACT WILL THE TRANSACTION HAVE ON THE CREDIT RATING OF LIBERTY UTILITIES?

A. The financing plan for the acquisition of the shares of Empire is designed to maintain a strong investment grade rating. Based on discussions with Standard & Poor's undertaken prior to announcement of the Empire transaction, we do not anticipate any changes to Liberty Utilities' current investment grade BBB credit rating and believe that the Empire acquisition will be supportive of maintaining the rating.

Q. IS THE PURCHASE PRICE FOR EMPIRE REASONABLE?

A. Yes. Empire conducted a competitive bid process, and as a result, a reasonable price was obtained by Empire. We believe Liberty Utilities' local focus and commitment to the Empire management team were instrumental in the success of our bid. To further demonstrate the reasonableness of our bid, financing for all of the equity required to complete the transaction has already been secured through the successful issuance of mandatorily convertible debentures by the parent of Liberty Utilities. This is discussed further in the testimony of Mr. Eichler.

Q. WAS THERE A PREMIUM PAID?

A. Yes. While there was a premium paid above book value, LU Central will not seek to recover that premium from customers, and the payment of that premium should not have any effect on service to customers. In addition, because LU Central will not be seeking recovery of any premium, the need to balance the costs of that premium with operational synergies is moot since it is not our plan to justify the premium through the achievement of synergies. In fact, Liberty Utilities has not sought to recover a premium in any of the previous acquisitions it has completed.

Q. IS THERE ANY EFFECT OF THE PROPOSED TRANSACTION ON COMPETITION?

A. No. Liberty Utilities does not currently serve any customers in Kansas, and does not have any overlapping franchise territories with any of Empire's operations in other states in which it serves and therefore, competition levels will be preserved.

Q. ARE THERE ANY QUANTIFIABLE BENEFITS TO CUSTOMERS FROM THIS TRANSACTION?

A. Yes. Mr. Eichler's testimony provides a quantification of the benefits, which amounts to approximately $704,000 for Empire customers, of which approximately $35,000 relates to Kansas utilizing Empire's state allocations. These are in addition to the benefits I describe in my testimony. I also believe that future quantifiable benefits will inure to Kansas customers over the coming years. Examples of this are described in the transaction rationale in items such as increasing current asset utilization through the centralization of billing functions, and reducing costs related to each company's mid-term plans to evaluate its customer information systems. By reducing two large implementations to one, all customers of Empire and Liberty Utilities will benefit.

Q. IN REGARDS TO THE COMMISSION'S SECOND FACTOR, WHAT IMPACT WILL THE TRANSACTION HAVE ON THE ENVIRONMENT?

A. At minimum, there will be no impact on the environment, and in fact, it is likely there will be benefits. This is because one of Liberty Utilities' core strengths is that through its affiliates it has extensive experience in developing renewable energy infrastructure. Most recently, a 50 MW solar facility is being developed in Luning, Nevada to serve the renewable energy requirements of Liberty Utilities' electric distribution utility serving Lake Tahoe, California. This project not only provides renewable energy, but does so with a levelized cost of energy lower than what was available through market based power purchase agreements and was therefore approved by the California Public Utilities Commission. These types of benefits will ensure that Kansas customers benefit from the expanded management capability that will be available to Empire. Further, Empire will continue to comply with all environmental laws and regulations as it does today.

Q. IN REGARDS TO THE COMMISSION'S THIRD FACTOR, WILL THE PROPOSED TRANSACTION BE BENEFICIAL ON AN OVERALL BASIS TO STATE AND LOCAL ECONOMIES AND TO COMMUNITIES IN THE AREA SERVED BY EMPIRE?

A. Yes. As I explain in my testimony, there are many benefits to the transaction, including Liberty Utilities' commitment to the local communities in which it operates as well as the establishment of a regional board. In addition, Liberty Utilities has significant experience serving customers in similar types of communities as those currently served by Empire. Further, Liberty Utilities has committed to maintaining employment for all current employees.

Q. IN REGARDS TO THE COMMISSION'S FOURTH FACTOR, WILL THE PROPOSED TRANSACTION PRESERVE THE JURISDICTION OF THE COMMISSION AND THE CAPACITY OF THE COMMISSION TO EFFECTIVELY REGULATE AND AUDIT PUBLIC UTILITY OPERATIONS IN THE STATE?

A. Yes. The Commission will continue to have jurisdiction over Empire, Empire will continue to comply with any ongoing regulatory commitments, and as explained by Mr. Krygier, the Commission will continue to have access to Empire's books and records as it does today.

Q. IN REGARDS TO THE COMMISSION'S FIFTH FACTOR, PLEASE EXPLAIN THE EFFECT OF THE TRANSACTION ON THE SHAREHOLDERS OF BOTH EMPIRE AND ALGONQUIN.

A. The effect of the transaction could perhaps be best described by pointing to some of the highlights identified in the press release issued at the announcement of the transaction. Some of the highlights identified included:

- Major regulated utility acquisition results in a pro-forma Algonquin Power & Utilities Corp ("APUC") asset base of C$8.9 billion.
- Empire shareholders to receive US$34.00 per common share in cash, representing a 21% premium to the closing share price on February 8, 2016.
- Aggregate purchase price of C$3.4 billion (US$2.4 billion), including assumed debt, represents a 1.49x multiple of Empire's projected rate base and a 9.2x multiple of Empire's 2017 EBITDA.
- Expected to be immediately accretive to APUC's earnings per share (EPS) and funds from operations per share (FFOPS), positioning APUC for further growth.

- Average annual accretion to EPS and FFOPS expected to be approximately 7% to 9% and 12% to 14%, respectively, for the three year period following closing.
- Acquisition is aligned with APUC's financial objectives and provides continuing support to APUC's 10% annual dividend growth rate target.
- APUC's financing plan designed to maintain strong investment grade credit rating.
- Shifts APUC's overall business mix towards regulated operations, with EBITDA from regulated operations increasing from 51% to 72%.
- Empire has complementary operations in the States of Missouri and Arkansas, with regional headquarters located in Joplin, Missouri.
- Empire has an experienced management team committed to providing customers with safe, reliable, cost effective utility services.
- Empire will maintain its headquarters in Joplin after the acquisition.
- APUC expects to retain all existing Empire employees and the Empire management team will lead Liberty Utilities' Central region.

Q. IN REGARDS TO THE COMMISSION'S SIXTH FACTOR, DOES THE TRANSACTION MAXIMIZE THE USE OF KANSAS ENERGY RESOURCES?

A. Yes. Empire currently purchases some of its electric supply from two wind farms located in Kansas. Those purchases will continue as they exist today, and Empire customers will continue to receive the benefits of those transactions. Further, as discussed above, Liberty Utilities will continue to seek further opportunities to develop and invest in Kansas energy resources.

Q. IN REGARDS TO THE COMMISSION'S SEVENTH FACTOR, WILL THE

TRANSACTION REDUCE THE POSSIBILITY OF ECONOMIC WASTE?

A. Yes. There will be no duplication of services provided, and as I explain in my testimony, there are opportunities for efficacies of scale.

Q. IN REGARDS TO THE COMMISSION'S EIGHTH FACTOR, WILL THE TRANSACTION HAVE ANY IMPACT ON PUBLIC SAFETY?

A. Empire's current employees will be maintained and will continue to provide the safe, reliable service they do today. In addition, Liberty Utilities has an established commitment to safety, which only adds to Empire's existing operations.

IV. <u>Operating Philosophy and Customer Service</u>

Q. WHAT IS LIBERTY UTILITIES' PHILOSOPHY REGARDING CUSTOMER SERVICE?

A. Liberty Utilities' approach to customer service is guided by the following principles:

- Our goal is to provide high quality service to all our customers at a reasonable price. We want satisfied customers and are willing to take steps necessary to achieve that objective.
- Our model is to deliver service to customers primarily through customer service representatives located in and dedicated to the local utility service territory. We believe customers respond most favorably to customer service representatives who are familiar with the service territory's geography, demography, and economy. Simply put, we want our customer service representatives to be from and be part of the communities they serve so they can experience what customers experience at the same time customers are experiencing them.

- We strive to continuously improve our customer service. To that end, we tailor our offerings locally and continually measure our performance in customer satisfaction surveys and "best in class" surveys where we seek to understand our performance relative to other utilities in the areas we serve.
- Liberty Utilities gives its local management teams significant authority and autonomy to determine how best to meet customers' needs. We believe managers and employees who are empowered are more inclined to take initiative and are more resourceful in resolving customer problems.
- Because the Liberty Utilities family of companies includes numerous utilities, we constantly seek ways to share information across companies and benefit from the knowledge and experience of affiliates while still leaving decision making in the hands of local management.
- As regulated businesses, we are committed to satisfying all legal regulatory obligations, and we believe local management and satisfied customers help enable us to achieve that objective.

Q. PLEASE ELABORATE ON LIBERTY UTILITIES' LOCAL APPROACH TO MANAGEMENT AND OPERATION OF ITS UTILITY SUBSIDIARIES.

A. Generally speaking, Liberty Utilities believes that if a function touches its employees, its customers, or its regulators, then it is best done within the service territory. This ensures an empathy with key stakeholders by ensuring that our employees are in tune with the needs of our customers and regulators. Additionally, we encourage employees to volunteer in local community events and participate in civic organizations such as the chamber of commerce and rotary. The local teams also make charitable donations supporting local causes in each community.

Q. SINCE ANNOUNCEMENT OF THE MERGER, HAS LIBERTY UTILITIES ENGAGED IN ANY OUTREACH TO LOCAL COMMUNITIES?

A. Absolutely. Immediately after announcing the transaction, our management team set out to engage the local communities. We have held meetings with each of the state commissions in Kansas, Missouri, Arkansas, and Oklahoma, other state and local officials, as well as meeting with current Empire employees and Empire retirees. We believe this outreach is important and it is fundamental to who we are as a company. We look forward to continuing these efforts both pre and post-merger.

Q. DOES LIBERTY UTILITIES PLAN TO MONITOR AND MEASURE HOW EFFECTIVE ITS CUSTOMER SERVICE EFFORTS ARE AND HOW SUCCESSFUL THESE EFFORTS ARE IN SATISFYING CUSTOMERS?

A. Yes. In other jurisdictions our affiliates have engaged an independent research firm to conduct an annual customer service and satisfaction survey. The results of these surveys have shown consistently good customer service ratings in all our utility service territories. A copy of the most recent customer satisfaction results in 2015 is attached to this testimony as Exhibit DP-1. I offer these survey results for two purposes. First, they illustrate our commitment to good customer service and customer satisfaction, a value shared by Empire. Second, the results show how we have used data from the surveys to identify areas for improvement and make improvement in those areas. Some of the changes we have made based on survey data include improvements to our website and bill presentation.

Q. IF THE PROPOSED ACQUISITION OF EMPIRE IS APPROVED, DOES LIBERTY UTILITIES INTEND TO IMPLEMENT ANNUAL CUSTOMER SURVEYS IN EMPIRE'S SERVICE AREA?

A. Yes, just like Empire does today, we will continue third party annual customer service surveys to continue finding the best ways to improve the customer experience.

Q. WHAT OTHER PROGRAMS TO IMPROVE CUSTOMER SERVICE AND CUSTOMER SATISFACTION DOES LIBERTY UTILITIES INTEND TO IMPLEMENT IF THE ACQUISITION IS APPROVED?

A. The Empire team provides great service today, continuous improvement is part of our philosophy. As such, one example of an area that may be evaluated is the opportunity to further reopen walk in centers in local communities. Like any potential change, we will evaluate what is best for the utility and its customers.

V. LIBERTY UTILITIES' OPERATIONAL EXPERIENCE

Q. YOU PREVIOUSLY TESTIFIED THAT FOLLOWING THE MERGER, EMPIRE WILL BE A WHOLLY-OWNED SUBSIDIARY OF LU CENTRAL. PLEASE DESCRIBE LIBERTY UTILITIES EXPERIENCE IN THE REGULATED UTILITY BUSINESS AND THE ROLE IT WOULD PLAY IN EMPIRE'S POST-MERGER OPERATIONS.

A. Liberty Utilities has deep experience in the regulated utility business. We acquired our first regulated utility approximately fifteen years ago and have grown to serve over 560,000 customers today; our customer roster will increase to nearly 800,000 customers with the addition of Empire. Our utility platform includes regulated water, wastewater, natural gas and electric utilities in eleven states across the country. In California and New Hampshire together, Liberty Utilities serves approximately 93,000 electric customers; our gas distribution utilities in Georgia, Illinois, Iowa, Massachusetts, Missouri and New Hampshire together serve approximately 292,000 customers, and; our water distribution and wastewater collection utility systems serve approximately 177,000 customers in Arizona, Arkansas, California, Illinois, Missouri, Montana and Texas. We see the addition of Empire as a perfect fit into our current operations. After the acquisition closes, we will add to our customer counts in Missouri and Arkansas while expanding our total states served from eleven to thirteen. With the addition of Empire's customers in Kansas and Oklahoma, Liberty Utilities overall customer count will increase from approximately 560,000 to nearly 800,000. Operationally, one of the customer benefits of this transaction is that the existing Empire senior leadership team will continue to run all current Empire operations based out of Joplin and assume additional oversight responsibilities for existing Liberty Utilities Arkansas, Texas, Missouri, Iowa and Illinois operations. With such a regional oversight model, customers of Empire and other Liberty Utilities regulated operations will see benefits from best practices, a deeper knowledge bench and a larger management resource pool that all benefit customers.

Q. WHAT IS LIBERTY UTILITIES' OVERALL PHILOSOPHY REGARDING OPERATION OF ITS REGULATED UTILITY BUSINESSES?

A. Liberty Utilities uses a de-centralized approach to operating its regulated utility business, which emphasizes the importance of local management and local control of day-to-day business operations. This is especially true for customer service activities and employee and community outreach activities. We believe these activities are best performed locally.

Evidence of this approach is seen from our operating history. When we acquired utility assets in California, Massachusetts, New Hampshire, Georgia, Arkansas and Missouri, we established a local headquarters in the service area to provide critical customer and regulator facing functions like customer service, billing, and regulatory. We established a local leadership team empowered to make the right business decisions for our customers and other stakeholders. Our commitment to Empire to maintain the employees and Joplin headquarters is consistent with our approach to management of our utility businesses.

Even though we generally favor performing activities locally, where the quality and empathy of a service is not prejudiced and there is an economy of scale benefit, we do provide certain non-customer, non-regulator, non-employee facing services centrally. For example, treasury, information technology, insurance and risk management are provided centrally which provides the benefits of allowing a more sophisticated service group, delivers certain economies of scale and facilitates the standardization of these activities. When structured and provided correctly, providing these selected services centrally does not detract from the local presence we believe our customers prefer.

Q. HOW DOES THIS OPERATING PHILOSOPHY AFFECT THE WAY LIBERTY UTILITIES APPROACHES THE MANAGEMENT AND OPERATION OF ITS SUBSIDIARIES?

A. For any utility continually striving to achieve the highest level of customer satisfaction and maintaining strong relationships with regulators, customers, and the communities in which they serve, we believe that there is no substitute for local management, local decision-making, and local operational control. Liberty Utilities believes our utility affiliates can best meet the needs of their stakeholders by having operational decisions made by individuals who are located in or near the communities they serve and who maintain regular contact with customers and regulators. As I noted earlier in my testimony, Empire's Joplin management team and employee group will remain intact following the merger and that team will continue to have full oversight for the company's utility operations.

VI. TRANSITION PLANNING

Q. DOES LIBERTY UTILITIES HAVE AN OVERARCHING APPROACH TO THE INTEGRATION OF EMPIRE IN TO THE LIBERTY UTILITIES FAMILY?

A. Yes. In its simplest terms, the transition should be seamless to customers from a customer service, reliability, rates and operational perspective. We are confident that this will be the case for Empire given that the current operations will continue as they exist today and only the ownership of Empire's shares will change hands.

Q. PLEASE UPDATE THE COMMISSION ON THE STATUS OF THE TRANSITION BETWEEN THE TWO COMPANIES.

A. Having overseen seven utility transitions resulting from acquisitions in the past five years, Liberty Utilities has developed a core competency in performing the activities associated with acquisition of additional regulated utilities. In the case of Empire, Liberty Utilities has made certain specific commitments regarding the transition, including the following:

- As discussed elsewhere in my testimony, Liberty Utilities will establish a "Central Region" which will be headquartered in Joplin, Missouri. This regional office will provide senior leadership to the current operations of Empire and Liberty Utilities' gas operations in Missouri, Illinois, and Iowa, and Liberty Utilities' water operations in

Missouri, Arkansas, Missouri and Texas. Combined, this regional organization will serve approximately 340,000 customers. The remainder of Liberty Utilities' operations in the United States will be similarly realigned under Liberty East and Liberty West regions. The Central Region will be the largest of the regions. This will provide the benefits of the depth of the Empire management team to all Liberty Utilities mid-west and central customers.

- Bradley Beecher will be offered the role of Chief Executive Officer of the Central Region, providing continuity and added breadth and depth to the Liberty Utilities management team.
- The Empire brand will be maintained for a minimum of five years. This will allow the rich history of Empire to continue and will provide time to educate customers and the public regarding the Liberty Utilities brand and brand promise.
- Empire's current Board of Directors will be offered positions to continue serving the LU Central region through a regional board of directors whose role is to provide governance and guidance to local issues affecting the utility. This will be important to maintaining a true local presence and experience for our customers.

Q. WHAT STAGE IS YOUR TRANSITION PROCESS CURRENTLY IN?

A. We are in the preliminary stages of transition planning and will continue to build out our plans as we progress through the regulatory approval process and ultimately the closing of the transaction. Currently, Liberty Utilities and Empire are evaluating each other's capabilities, strengths, functions, systems, processes, and policies and determining where opportunities may present themselves to create efficiencies, capitalize on scale, enhanced management capabilities, and eliminate redundancies. This stage is typical for the point in time we are at relative to having signed the merger agreements and consistent with previous transitions.

Q. IF YOU HAVE NOT COMPLETED THE TRANSITION PLANNING PROCESS, HOW DO YOU KNOW YOU WILL MEET THE STANDARD THAT THE PROPOSED TRANSACTION "PROMOTES THE PUBLIC INTEREST?"

A. There are several reasons for my confidence. Most importantly, nothing is changing as a result of the acquisition from a customer service or operational perspective. After the acquisition closes, retaining the Empire employees and management team allows us to continue providing safe, reliable service along with a positive customer experience. Second, our teams have already identified opportunities where the business combination can result in greater scale benefitting customers and the respective companies. One example is the bill printing process; Empire owns a sophisticated bill printing machine located in Joplin that has some excess capacity available. Liberty Utilities currently outsources its bill printing function. By combining our respective bill print requirements at the Joplin facility, greater utilization of equipment and greater scale can emerge. Another example is the fees associated with the Securities and Exchange Commission listings, audit fees, and other public company costs which will be saved given that Empire will no longer be a publicly traded corporation after the acquisition. These are two examples that provide us confidence that our business combination will result in benefits to stakeholders.

Q. DOES THE ACQUISITION POSE ANY OPPORTUNITIES TO LEVERAGE GREATER SCALE IN CUSTOMER SERVICE?

A. Yes. Another opportunity to capture the benefit of scale is the potential combination of our respective needs for customer information systems ("CIS"). At present, Empire is undertaking an upgrade of its current CIS after which the system will no longer be supported by the vendor. Similarly, Liberty Utilities, as part of a continual review of its systems and operations, is currently evaluating its CIS needs and capabilities. As a result, this presents a unique opportunity to achieve greater scale through the adoption of one CIS to serve all Liberty Utilities operations. Based on my experience, there will be other areas of opportunity identified throughout the process, and therefore, I am confident that there will be further opportunities to gain advantage from the business combination.

Q. DOES LIBERTY UTILITIES BRING FINANCIAL STRENGTH TO EMPIRE'S FUTURE OPERATIONS?

A. Yes. As explained further in the testimony of Mr. Eichler, the financial strength of the combined organizations will continue to have strong capital market access and continue a strong investment grade balance sheet which is important to the future success of Empire's operations.

Q. ARE THERE OTHER OPPORTUNITIES PRESENTED BY THIS ACQUISITION?

A. Yes. As previously discussed in my testimony, from a non-financial perspective, this transaction will add significant capabilities in management to both organizations. From a Liberty Utilities perspective, in Empire we are acquiring a company with significant management strength in utility operations which will help provide context and management best practices. Similarly, Liberty Utilities, through its affiliates brings not only distribution utility expertise but also expertise in the development and management of renewable energy sources.

Q. IS ANYTHING DIFFERENT ABOUT THIS TRANSITION THAN PRIOR ACQUISITIONS?

A. Yes. This acquisition comes with a standalone utility operation which will allow us to stage and implement the transition in a manner that is most ideal for LU Central's customers. Prior transactions have typically not come with systems or senior management teams in place. This increases our confidence that we expect the transition to be seamless.

Q. PLEASE DESCRIBE THE RESOURCES AND MANAGEMENT EXPERTISE LIBERTY UTILITIES WILL PROVIDE TO ASSIST THE CURRENT JOPLIN MANAGEMENT TEAM POST-MERGER.

A. As I mentioned above, Liberty Utilities has a deep utility knowledge pool with over 1,000 employees in water, wastewater, natural gas and electric utilities in eleven states which span all aspects of utility operations. In addition, Liberty Utilities' affiliates have significant experience developing and operating renewable generation assets through its ownership or interest in hydroelectric, wind, solar and thermal facilities with a combined gross generating capacity of approximately 120 Megawatt ("MW"), 700 MW, 35 MW and 335 MW, respectively. This experience may be useful as the region considers the role of renewable generation in renewable portfolio standards or otherwise. Post-merger, we will be able to share our talent pool with the Empire team and vice-versa which can only stand to make our organization stronger through the sharing of best practices.

Q. HOW WILL THE PROPOSED TRANSACTION AFFECT EMPIRE'S UTILITY OPERATIONS IN KANSAS IMMEDIATELY FOLLOWING THE MERGER?

A. The proposed merger will have no effect on Empire's utility operations in Kansas or Empire's customers. From a customer standpoint, we expect the merger will be seamless, and all rates and tariffs in effect at the time of the merger will continue to apply. We also do not expect to significantly alter Empire's field operations as a result of the transaction because we will offer employment to all current employees. The continued employment of these knowledgeable and experienced employees will benefit Empire's customers in all the states where it provides service.

Q. WILL KANSAS CUSTOMERS BENEFIT FROM BEING A PART OF LU CENTRAL AND ITS EXPANDED OPERATIONS BASE?

A. While there are no operational changes to other utilities owned by LU Central, the operations in Kansas will be enhanced by the transaction as Liberty's current operations will be able to benefit from the enhancements outlined above. More specifically; however, the acquisition allows for access to a senior management team with significant utility expertise in gas, water, and electric utility operations based closer to its operations in Joplin, Missouri. This proximity will allow for enhanced responsiveness to respond to utility operating requirements. In addition, through a regional board of directors, the management teams in Missouri will have opportunities to receive guidance and counsel from local business and community leaders who can provide insight to the emerging issues within the service territory. Further, the utilities will now be a part of a division with approximately 340,000 customers in a company with nearly 800,000 customers. This scale will allow future opportunities to capitalize on efficiencies as they emerge.

Q. FOLLOWING THE PROPOSED MERGER, WHAT ASSURANCES CAN YOU PROVIDE THAT EMPIRE WILL CONTINUE TO PROVIDE SAFE, ADEQUATE,

RELIABLE, AND COST-EFFECTIVE UTILITY SERVICE TO ITS KANSAS CUSTOMERS?

A. Liberty Utilities has the management, technical, and financial expertise and capabilities necessary to ensure Empire continues to provide its Kansas customers with safe, adequate, reliable, and cost-effective electric, natural gas, and water utility services. Liberty Utilities and its utility affiliates have been in the regulated utility business for more than a decade and over that period have developed a strong customer service record for both existing operations and the utilities they acquire. In addition, with the retention of Empire's employees, we anticipate providing the same great safe, adequate, cost-effective and reliable service that Empire customers have come to expect.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes it does.

VERIFICATION

PROVINCE OF ONTARIO)
) ss:
CANADA)

I, David Pasieka, being first duly sworn on oath, depose and state that I am the witness identified in the foregoing Direct Testimony of David Pasieka; that I have read the testimony and am familiar with its contents; and that the facts set forth therein are true and correct.

____

SUBSCRIBED AND SWORN to before me this 16th day of MARCH, 2016.

____

Notary Public

Commission/Appointment Expires: Does not expire

Liberty Utilities

CUSTOMER SATISFACTION TRACKING
MIDSTATES (IL, IA, MO) GAS

OCTOBER 2015

LUTH research

Exhibit DP-1

OVERALL AWARENESS & SATISFACTION

Overall satisfaction has remained consistently high at 83%.

61% Very Satisfied + 22% Somewhat Satisfied = 83% Overall Satisfaction

- Notably, three in five Midstates customers reported that they were very satisfied.
- However, the percentage of customers reporting dissatisfaction (9%) increased significantly from 2014 (6%).

The most common reason customers were satisfied was that they have never had a problem or complaint with Liberty (42%).

- A smaller portion were also satisfied because of good gas service and friendly customer service.

Why Satisfied (Unaided)

- 42%* No problem/complaint
- 14%^ Service is good
- 12%^ Friendly customer service

Problems with billing was the top reason customers were dissatisfied with Liberty (38%).

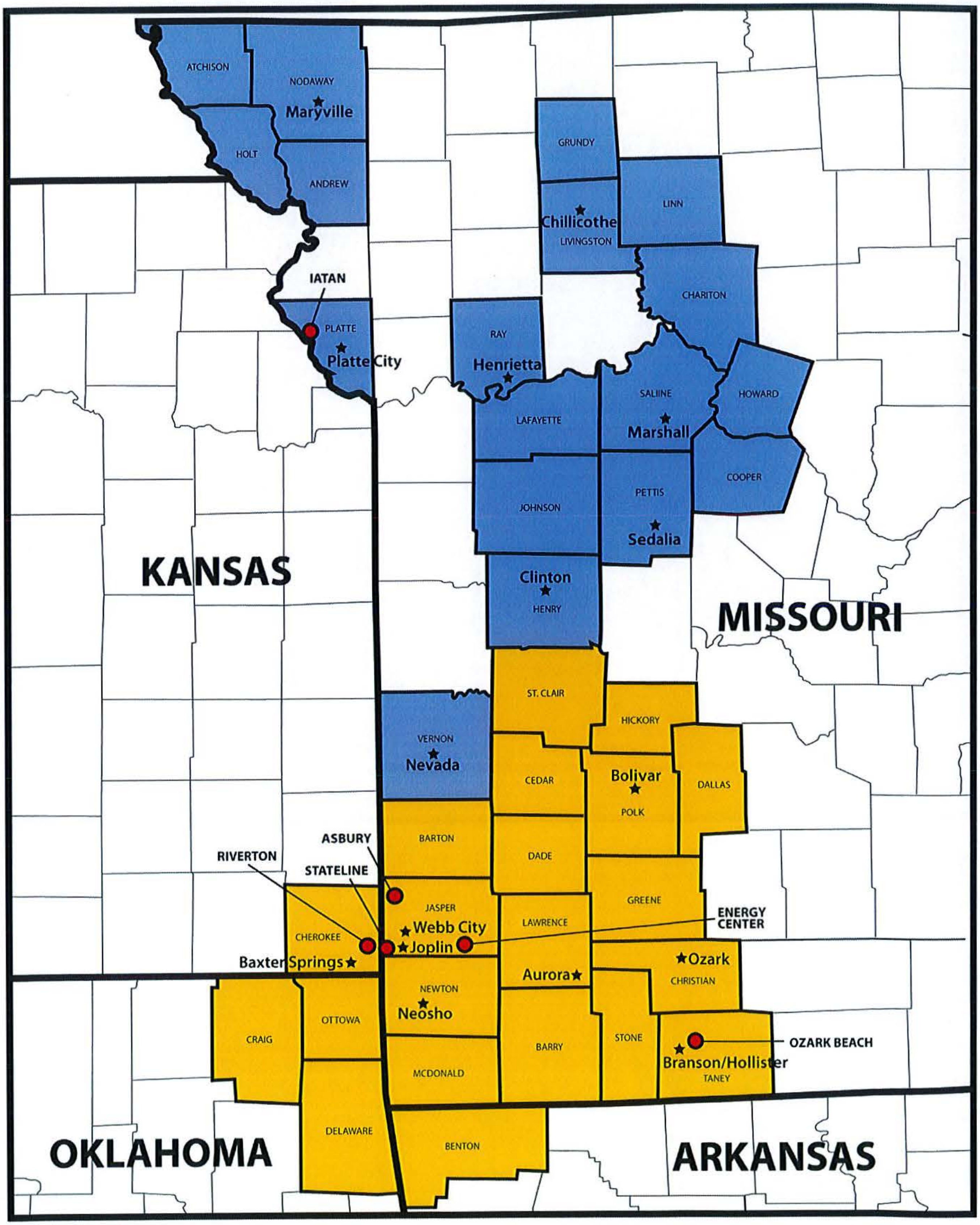
- Nearly a third of dissatisfied customers were also dissatisfied due to high costs.

Why Dissatisfied (Unaided)

- 38% Billing problems
- 31% Cost is too high
- 24% Poor customer service

^ Significantly higher than 2014 scores
* Significantly lower than 2014 scores

APPENDIX A



GAS

ELECTRIC

POWER PLANT

SERVICE CENTER

THE EMPIRE DISTRICT ELECTRIC COMPANY

ELECTRIC AND GAS SERVICE TERRITORIES

THE EMPIRE DISTRICT ELECTRIC COMPANY
Communities Affected

Incorporated:

Baxter Springs
Columbus
Galena
West Mineral
Roseland
Scammon
Treece
Weir

Unincorporated:

Camp 42
Carona
Hallowell
Lowell
Melrose
Riverton

APPENDIX B

Delaware

The First State

I, JEFFREY W. BULLOCK, SECRETARY OF STATE OF THE STATE OF DELAWARE, DO HEREBY CERTIFY "LIBERTY UTILITIES (CENTRAL) CO." IS DULY INCORPORATED UNDER THE LAWS OF THE STATE OF DELAWARE AND IS IN GOOD STANDING AND HAS A LEGAL CORPORATE EXISTENCE SO FAR AS THE RECORDS OF THIS OFFICE SHOW, AS OF THE THIRD DAY OF MARCH, A.D. 2016.

AND I DO HEREBY FURTHER CERTIFY THAT THE ANNUAL REPORTS HAVE BEEN FILED TO DATE.

AND I DO HEREBY FURTHER CERTIFY THAT THE FRANCHISE TAXES HAVE BEEN PAID TO DATE.

Jeffrey W. Bullock, Secretary of State

5956697 8300

SR# 20161473240

Authentication: 201927487

Date: 03-03-16

You may verify this certificate online at corp.delaware.gov/authver.shtml

APPENDIX C

CONFIDENTIAL

APPENDIX D

Delaware

The First State

I, JEFFREY W. BULLOCK, SECRETARY OF STATE OF THE STATE OF DELAWARE, DO HEREBY CERTIFY THE ATTACHED IS A TRUE AND CORRECT COPY OF THE CERTIFICATE OF INCORPORATION OF "LIBERTY UTILITIES (CENTRAL) CO.", FILED IN THIS OFFICE ON THE FIFTH DAY OF FEBRUARY, A.D. 2016, AT 4:27 O`CLOCK P.M.

A FILED COPY OF THIS CERTIFICATE HAS BEEN FORWARDED TO THE NEW CASTLE COUNTY RECORDER OF DEEDS.

Jeffrey W. Bullock, Secretary of State

5956697 8100
SR# 20160630760

Authentication: 201788632
Date: 02-05-16

State of Delaware
Secretary of State
Division of Corporations
Delivered 04:27 PM 02/05/2016
FILED 04:27 PM 02/05/2016
SR 20160630760 - File Number 5956697

CERTIFICATE OF INCORPORATION OF LIBERTY UTILITIES (CENTRAL) CO.

ARTICLE I

The name of the corporation is **Liberty Utilities (Central) Co.**

ARTICLE II

The address of the corporation's registered office in the State of Delaware is Corporation Trust Center, 1209 Orange Street, City of Wilmington, County of New Castle, State of Delaware 19801. The name of its registered agent at such address is The Corporation Trust Company.

ARTICLE III

The purpose of the corporation is to engage in any lawful act or activity for which corporations may be organized under the General Corporation Law of the State of Delaware.

ARTICLE IV

The total number of shares which the corporation is authorized to issue is 10,000 shares of common stock, $0.01 par value per share.

ARTICLE V

The name and mailing address of the incorporator is as follows:

Tammy Eddings
4801 Main Street
Kansas City, Missouri 64112

ARTICLE VI

The Board of Directors is authorized to adopt, amend, or repeal the Bylaws of the Corporation, but the stockholders may adopt additional Bylaws and may amend or repeal any Bylaws whether adopted by them or otherwise.

ARTICLE VII

The Corporation is to have perpetual existence.

ARTICLE VIII

The number of directors of the Corporation shall be fixed by, or in the manner provided in, the Bylaws of the Corporation.

ARTICLE IX

The corporation reserves the right to amend, alter, change or repeal any provision contained in this Certificate of Incorporation, in the manner now or hereafter prescribed by statute, and all rights conferred upon stockholders herein are granted subject to this reservation.

ARTICLE X

To the fullest extent permitted by law, a director of the Corporation shall not be personally liable to the Corporation or its stockholders for monetary damages for breach of fiduciary duty as a director. If the General Corporation Law or any other law of the State of Delaware is amended after the filing of this Certificate of Incorporation with the Delaware Secretary of State to authorize corporate action further eliminating or limiting the personal liability of directors, then the liability of a director of the Corporation shall be eliminated or limited to the fullest extent permitted by the General Corporation Law as so amended.

IN TESTIMONY WHEREOF, the undersigned, for the purpose of forming a corporation pursuant to the General Corporation Law of the State of Delaware, does make, file, and record this Certificate, and does declare and certify that the facts herein stated are true, and has accordingly hereunto set her hand this 5th day of February, 2016.

By: /s/ Tammy Eddings
Tammy Eddings
Incorporator

APPENDIX E
CONFIDENTIAL

APPENDIX F

For Profit Articles of Incorporation

The name of the corporation:

Liberty Sub Corp.

File date: 02/09/2016
File time: 09:26:41
Business Entity Number: 8196867

Registered office in Kansas:

112 SW 7TH STREET SUITE 3C
TOPEKA, Kansas
66603

Name of the resident agent at the registered office:

The Corporation Company, Inc.

Mailing address for official mail:

Liberty Sub Corp.
112 SW 7TH STREET SUITE 3C
TOPEKA, KS
66603 USA

The nature or purpose of the business entity:

The purpose of this business entity is to engage in any lawful act or activity for which the entity may be organized under the laws of Kansas.

This business entity will have the ability to issue stock.

Total number of shares of stock the corporation is authorized to issue:

Shares: 10000
Type: Common
Value: 1.00/per share

Special designations, powers, rights, limitations or restrictions applicable to any class of stock or any special grant of authority to be given to the board of directors.

Will the powers of the incorporator(s) terminate upon filing the articles of incorporation?

Yes

Director(s) information:

Ian Robertson 354 Davis Rd, Suite 100 Oakville ON L6J2X1 CND	Greg Sorensen 354 Davis Rd, Suite 100 Oakville ON L6J2X1 CND	Richard Leehr 354 Davis Rd, Suite 100 Oakville ON L6J2X1 CND

Expiration date of the corporate existence:

Perpetual

Tax closing month:

December

Incorporator information:

Tammy Eddings
4801 Main Street Suite 1000
Kansas City MO
64112 USA

"I declare under penalty of perjury pursuant to the laws of the state of Kansas that the foregoing is true and correct."

Execution date: 02/09/2016

The signature(s) of the incorporator(s):

Tammy Eddings

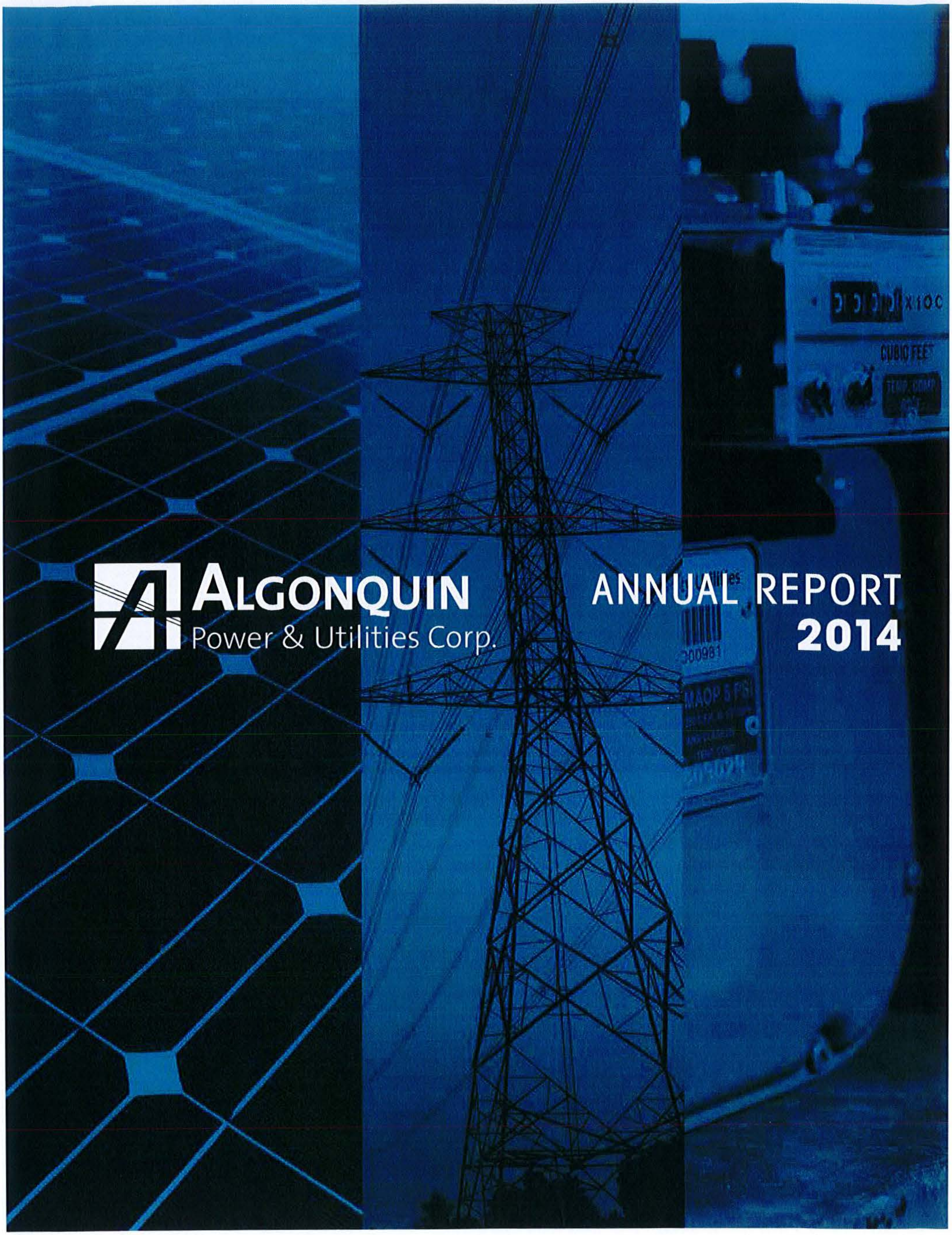
Tammy Eddings

I, Kris W. Kobach, Secretary of State of Kansas, do hereby certify that this is the true and correct copy of the original document filed electronically on 02/09/2016.

Kris W. Kobach

Kansas Secretary of State
Memorial Hall, 1st floor - 120 SW 10th Ave. - Topeka, Kansas 66612-1594
phone: (785) 296-4564 - email: kssos@sos.ks.gov - url: http://www.sos.ks.gov/

APPENDIX G

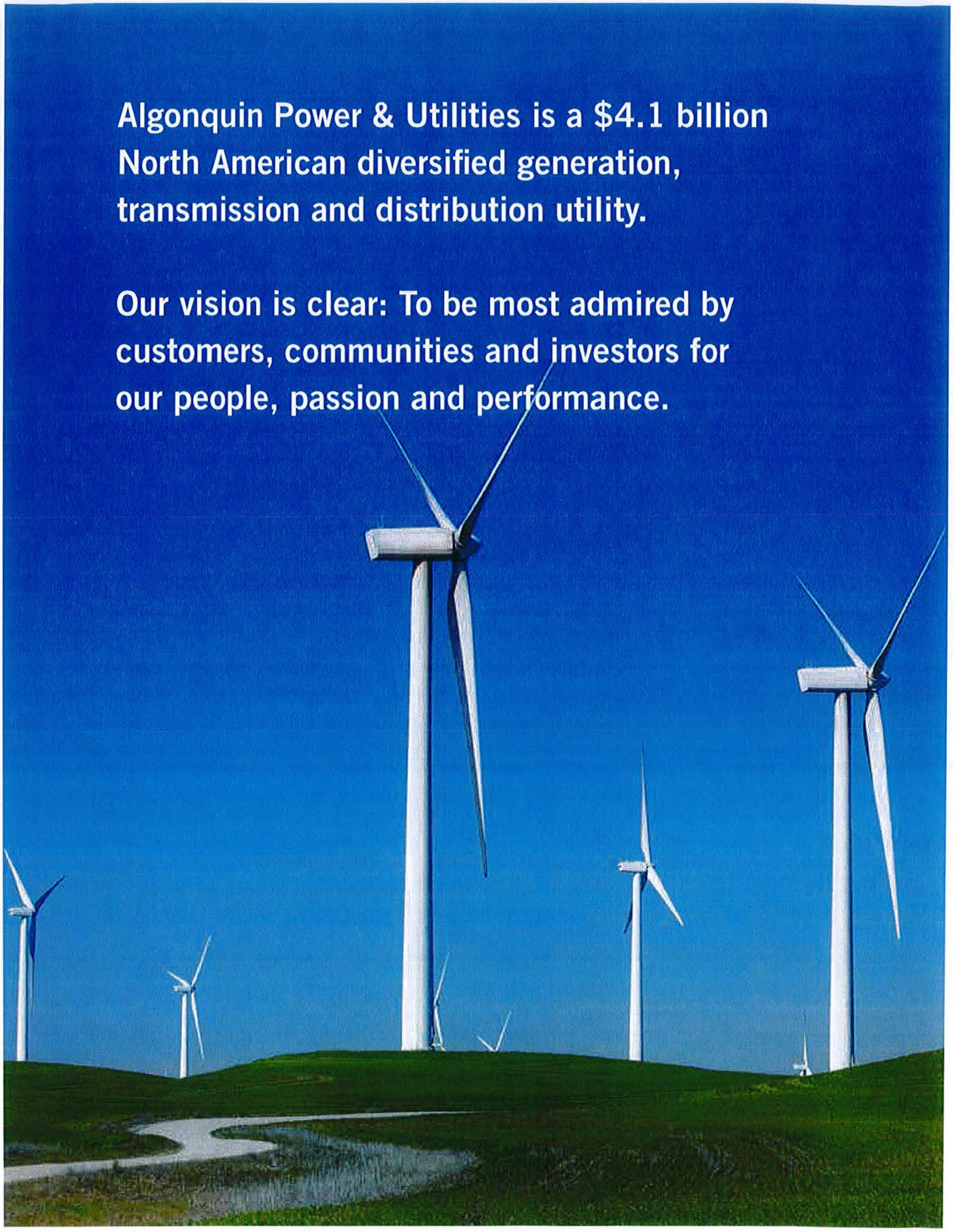


ALGONQUIN
Power & Utilities Corp.

ANNUAL REPORT 2014

Algonquin Power & Utilities is a $4.1 billion North American diversified generation, transmission and distribution utility.

Our vision is clear: To be most admired by customers, communities and investors for our people, passion and performance.



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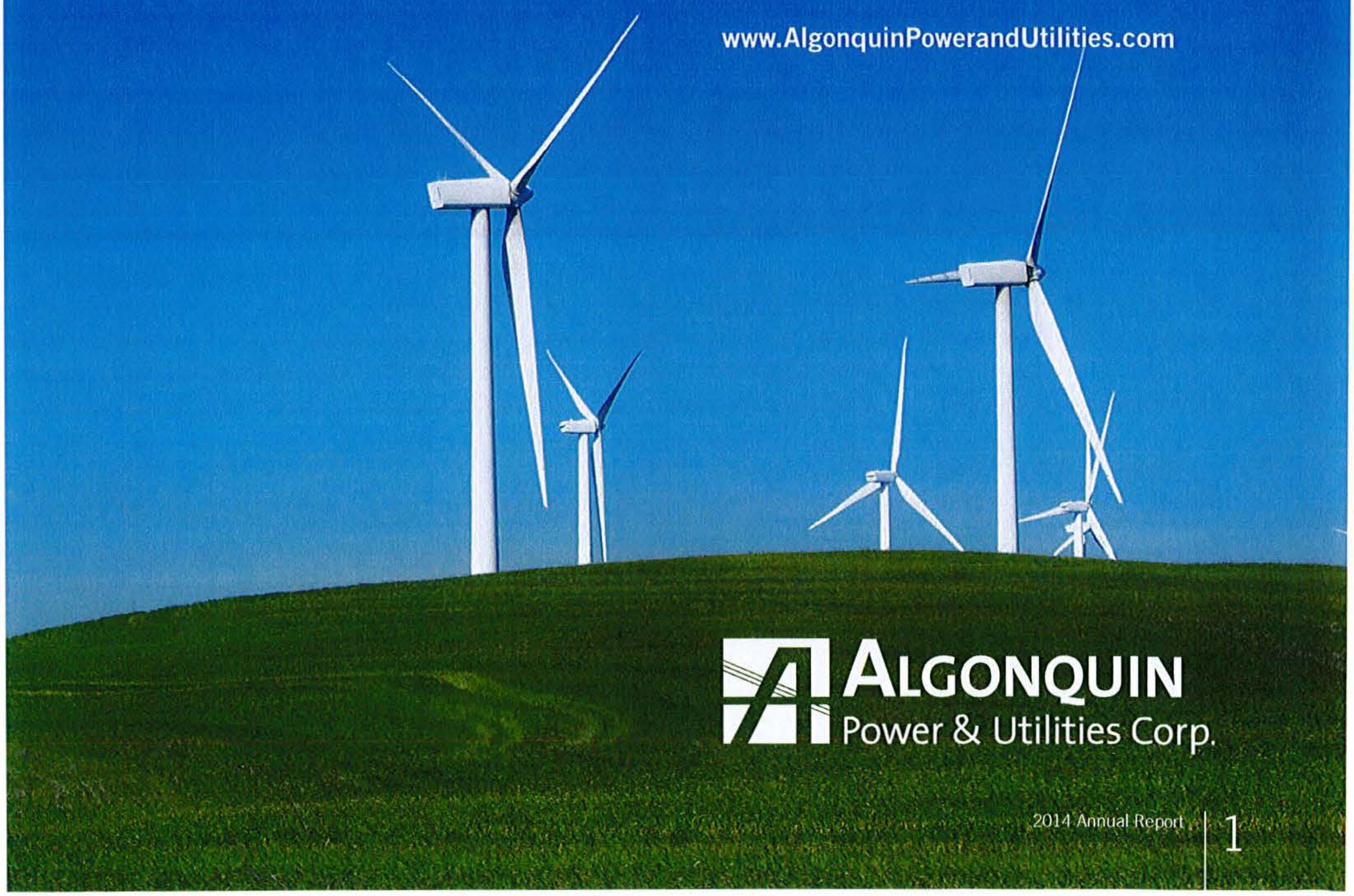
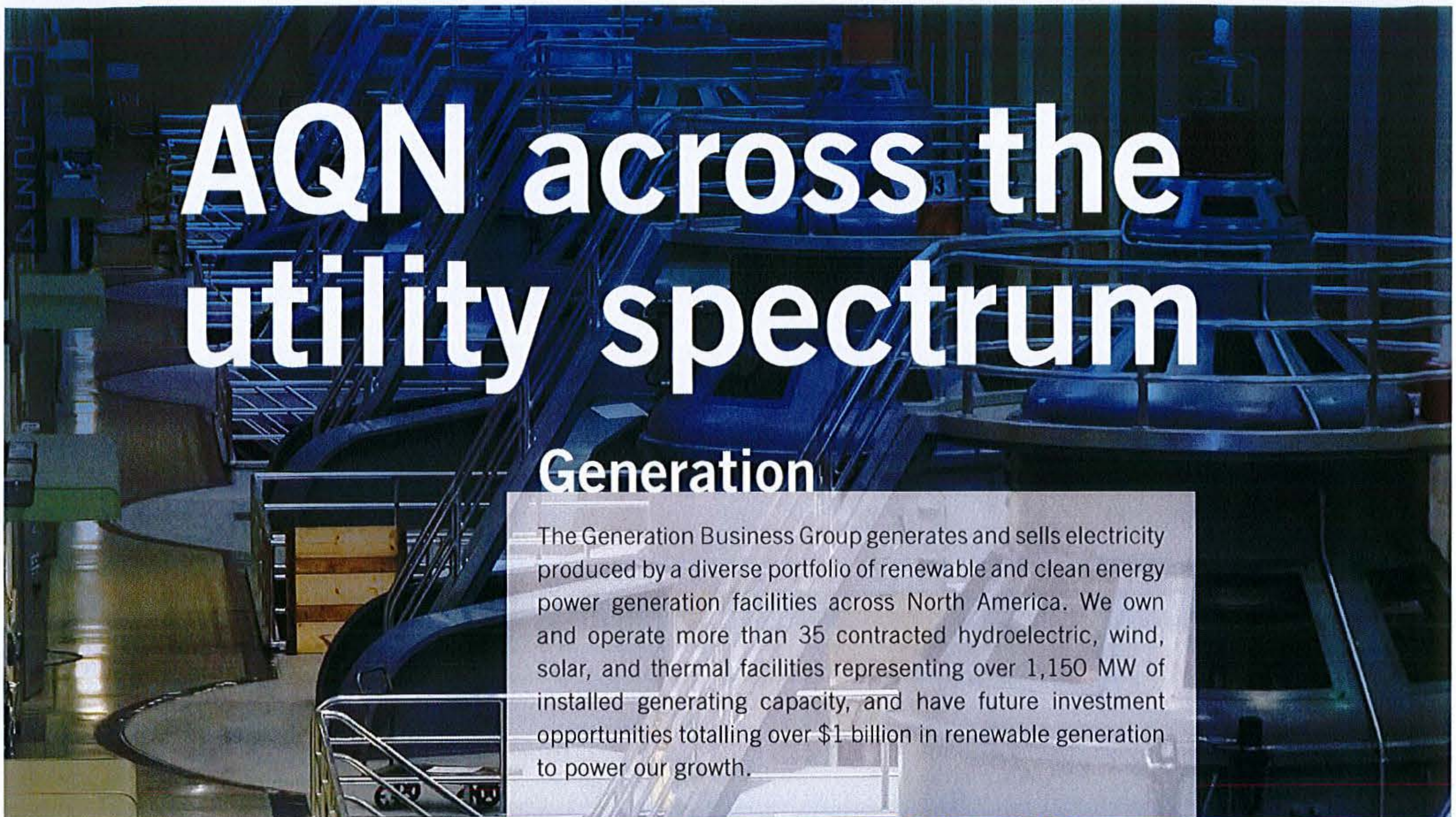
Toronto Stock Exchange: AQN

www.AlgonquinPowerandUtilities.com



ALGONQUIN Power & Utilities Corp.

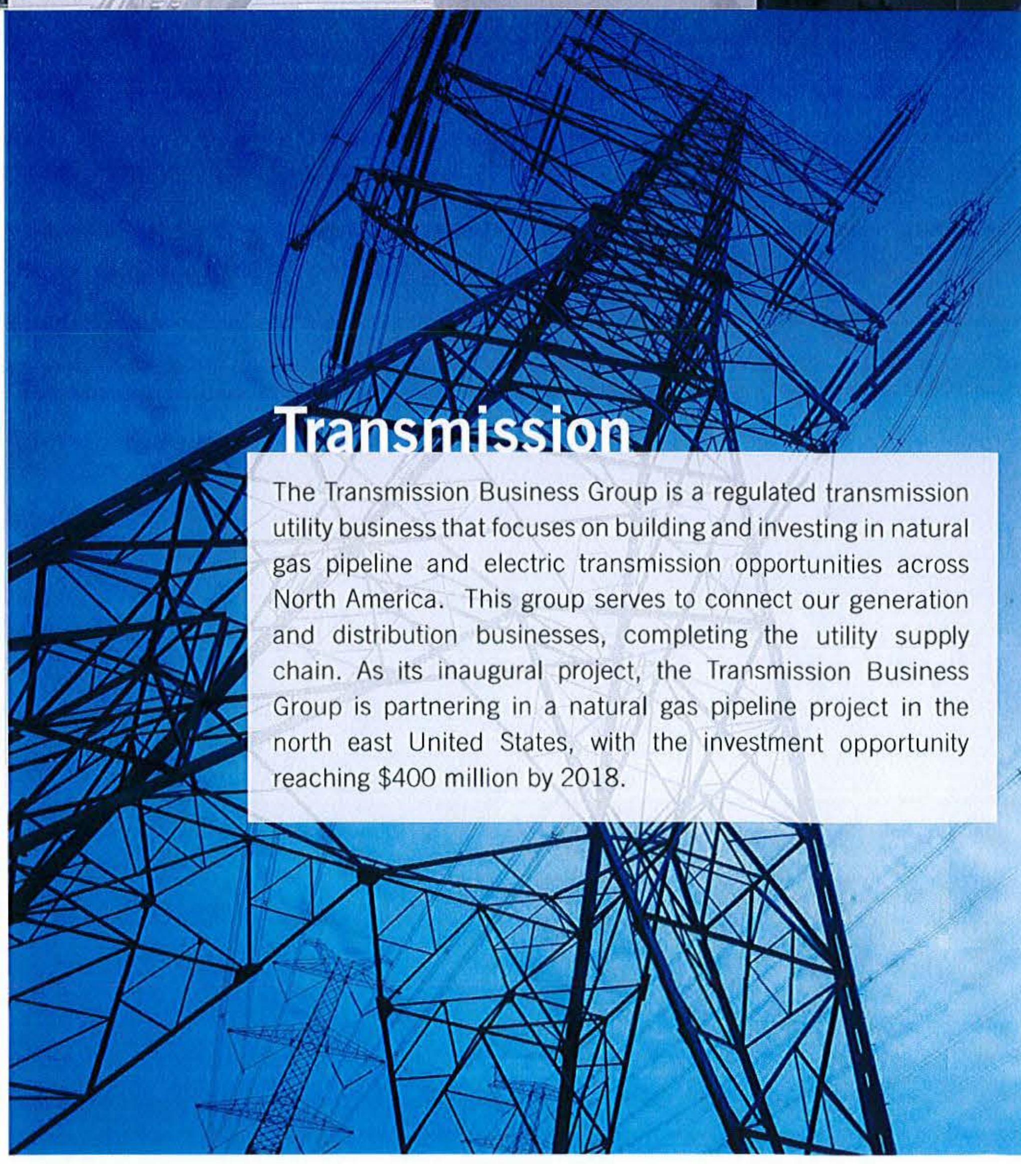
AQN across the utility spectrum



Generation

The Generation Business Group generates and sells electricity produced by a diverse portfolio of renewable and clean energy power generation facilities across North America. We own and operate more than 35 contracted hydroelectric, wind, solar, and thermal facilities representing over 1,150 MW of installed generating capacity, and have future investment opportunities totalling over $1 billion in renewable generation to power our growth.

Algonquin Power & Utilities is an integrated utility company participating across the utility spectrum - Generation, Transmission and Distribution.

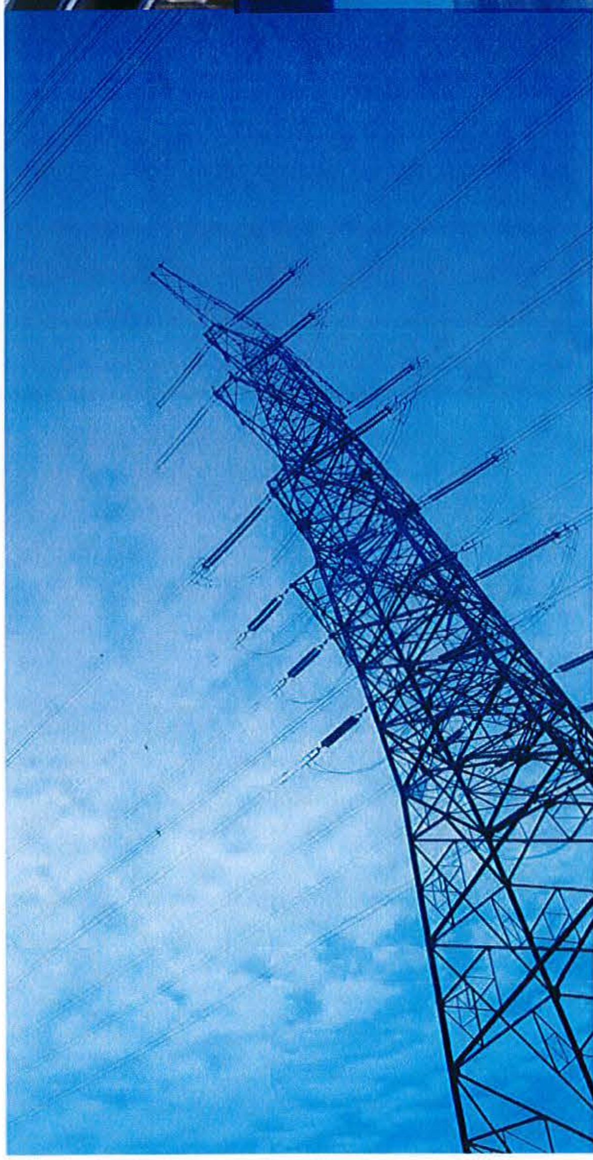


Transmission

The Transmission Business Group is a regulated transmission utility business that focuses on building and investing in natural gas pipeline and electric transmission opportunities across North America. This group serves to connect our generation and distribution businesses, completing the utility supply chain. As its inaugural project, the Transmission Business Group is partnering in a natural gas pipeline project in the north east United States, with the investment opportunity reaching $400 million by 2018.

Distribution

The Distribution Business Group owns and operates regulated water, natural gas and electricity distribution utilities in communities across the United States. We own and operate over 30 distribution utilities serving more than 488,000 customer connections across 10 states, with our focus on growth achieved through acquisitions and organic growth opportunities currently totaling $1.1 billion.



AQN by the numbers

1,275
employees

1,150
MW installed capacity

380
wind turbine generators

82,092
solar panels

76
hydroelectric generators

488,000
utility customers

10,785
km of gas distribution lines

1,920
km of electricity distribution lines

2,272
km of water distribution mains

14
year average contract length of power purchase agreements

2014 Achievements

Algonquin Power & Utilities is led by an experienced executive management team with over 65 years of combined experience in generation, transmission and distribution utilities. We have successfully grown the business for more than 20 years and now boast annual revenues of nearly $1 billion, total utility assets of more than $4 billion and a market capitalization of over $2 billion.

37% Annual total shareholder return

49% EBITDA[1] growth

14% Asset growth

50% Adjusted net earnings per share[1]

31% Cash flow per share

12% Dividend increase

2014 Financial Highlights

(in $ millions)

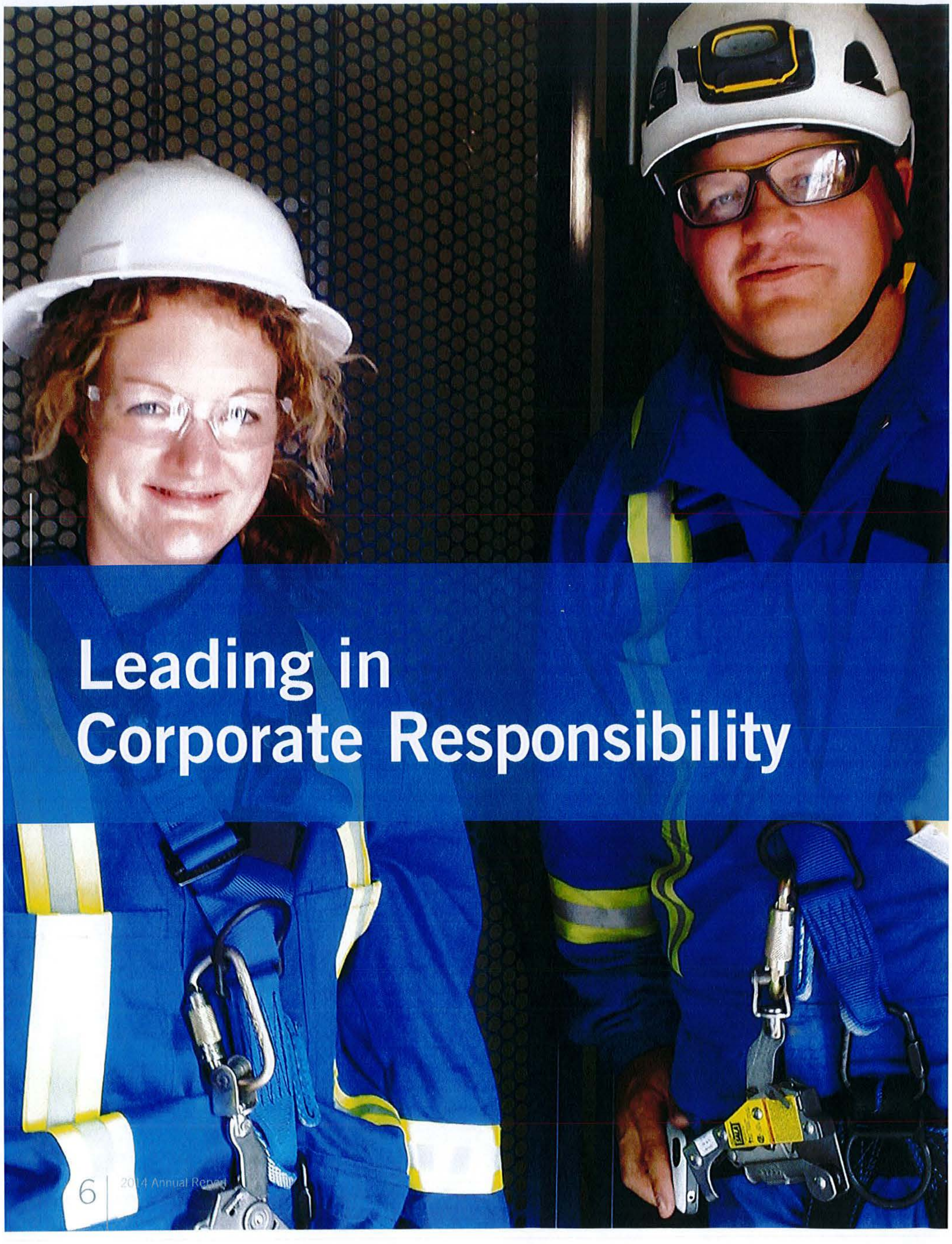
Revenue	2014	2013	2012
Generation Revenue	218.8	189.7	118.0
Distribution Revenue	724.8	485.2	230.8
Other	–	0.4	–
Total Revenue	**943.6**	**675.3**	**348.8**
Adjusted EBITDA[1]	**290.6**	**228.1**	**88.1**

Earnings, Funds from Operations and Dividends			
Adjusted Funds from Operations	206.5	154.9	66.8
Per Share	0.92	0.73	0.42
Adjusted Net Earnings	88.4	59.5	18.9
Per Share	0.37	0.26	0.11
Dividends to Shareholders	82.9	68.3	50.2
Per Share	0.37	0.33	0.30

Balance Sheet Data			
Total Assets	4,113.7	3,476.5	2,779.0
Long-Term Liabilities (includes current portion)	1,280.0	1,255.6	770.8
Number of Shares Outstanding as of Dec. 31	238,149,468	206,860,592	188,763,486
Renewable energy production (% of long term average)	**98%**	**95%**	**93%**
Utility Connections	**488,000**	**481,400**	**344,700**

[1]Non-GAAP Financial Measures

The terms "adjusted net earnings", "adjusted earnings before interest, taxes, depreciation and amortization", and "adjusted funds from operations" (together, the "Financial Measures") are used throughout this Annual Report. The Financial Measures are not recognized measures under GAAP. There is no standardized measure of the Financial Measures, 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 these Financial Measures can be found in the Management Discussion & Analysis section of this Annual Report.



Leading in Corporate Responsibility

Our vision is to be the utility company most admired by customers, communities and investors for our people, passion and performance. We will achieve this vision through our proven growth strategy, a passionate workforce and continuing commitment to corporate responsibility. As a leader in the North American utility industry, Algonquin Power & Utilities makes a conscious effort to conduct our business practices in a socially, economically, and environmentally responsible manner.

Our commitment is deeply rooted in our business; we pride ourselves on acquiring, developing, and operating assets that create sustainable, long-term value and benefit for all of our stakeholders. These stakeholders include our customers, communities, employees, the environment, and you – our valued shareholders. Corporate Responsibility is about connecting the gap between stakeholder value and financial performance, and we will continue to grow a value-driven corporation with our stakeholders at the forefront of thought and action.

Using the Global Reporting Initiative as our framework, we are pleased to have our first Corporate Responsibility Report available electronically, accessible through our website – www.AlgonquinPowerAndUtilities.com – via the SUSTAINABILITY tab. We encourage you to visit the site and read about our sustainability efforts. Going forward, Corporate Responsibility reporting will be an annual process as we launch new initiatives and develop those already in place. Our aim is to become more comprehensive and in-depth with our reporting efforts.

Letter to Shareholders

Ian Robertson
CEO

Ken Moore
Chairman of the Board of Directors

Dear Fellow Shareholders,
The year 2014 was a year of impressive growth for Algonquin Power & Utilities, and evident from our financial results, a year of unprecedented execution and evolution as one of North America's leading utility companies. Through continued successful integration of new acquisitions as well as organic growth, the completion of several development projects, and the formation of a new business group, we continued to exceed the expectations of our investors and stakeholders.

Our vision is to be the utility company most admired by customers, communities and investors for our people, passion and performance. In order to make this vision a reality, we strive to build an organization that delivers strong shareholder value by fostering an environment well positioned for success and continued long term growth.

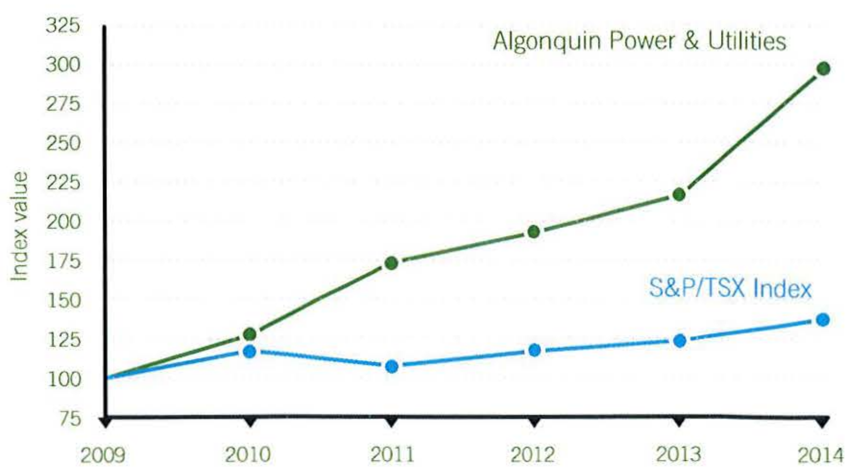
Here is how we make that happen.

People

We know that, at its root, our success stems from the significant contributions of our people. Algonquin Power & Utilities is proud to be represented by more than 1,250 employees – a number that continues to grow every day as we expand our diverse team of talented and motivated professionals. Each and every employee has played an important and valuable role in making this company what it is today.

In addition to our employees, we continue to expand the strength and diversity of our Board of Directors. This past year saw the appointment of two new members, Masheed Saidi and Dilek Samil. Ms. Saidi is a registered professional engineer with over 30 years of operational and business leadership

Total Return Performance



experience in the regulated utility industry. Ms. Samil brings over 30 years of finance, operations, and business experience in the regulated energy utility sector and generation and system operations. The strength of our Board of Directors is vital to our success through the continuation of exceptional corporate governance.

Passion

Foremost in our daily activities, it is our objective to conduct our operations in an environmentally sound and safe manner. We are proud that our 2014 safety record continues to surpass industry averages, and challenges world class performance. At Algonquin Power & Utilities we are passionate about the safety of our employees and our communities. Safety is and has always been a fundamental part of our company culture. 2014 saw the continuation of many safety-focused initiatives, including our "Drive to Zero" program, which is based on having no recordable or lost time injuries. We are pleased to note that 2014 saw continued improvement in our safety metrics, and we will continue to foster a working environment where safety is top of mind for every employee.

The financial success highlighted throughout this annual report confirms our ability to effectively execute on our projected financial goals and growth strategies.

We are also committed to delivering attractive shareholder value consistent with our vision of being a "must own" investment holding in the portfolio of every long minded investor. We are pleased with having delivered 2014 total shareholder return of 37% and reaching an all-time adjusted EBITDA high of $291M in 2014, an increase of more than 30% over 2013. Additionally, revenue was up 40% to $943 million and our overall market capitalization grew by 52% compared to 2013.

We are equally passionate about leading an organization that operates in a socially, ethically, and environmentally responsible manner. Sustainability is deeply-rooted in our company culture, and this past year we made tremendous advancements in launching our first on-line Corporate Responsibility report. Using the Global Reporting Initiative as our compass, this annual report formally documents our operational practices measured against a sustainability reporting framework as a means of understanding and communicating the accountability of our actions. To us, a successful business is one that not only serves our shareholders, but delivers value to all stakeholders including customers, communities and employees.

Performance

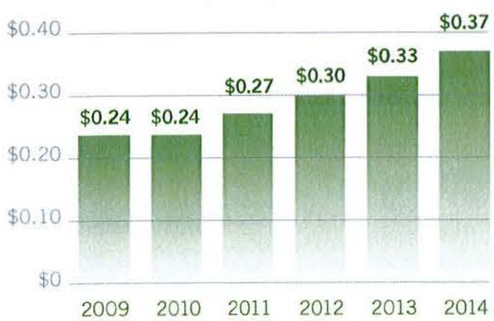
Generation

It was another active year for our Generation group, which saw the investment of over $200 million in new long term contracted renewable power projects.

As in previous years, 2014 saw the continuation of our strategic focus on growing our generation business through the development of green-field renewable power projects. We achieved commercial operation at our 24 MW St. Damase Wind Project in Quebec and our 10 MW Cornwall Solar Project in Ontario. We also made significant progress on the 24 MW Morse Wind Project

Our financial success was validated by the Board of Directors' decision in August to approve a 12.4% dividend increase from CDN $0.34 to U.S. $0.35 per common share.

Dividents per Share



in Saskatchewan and our 20MW Bakersfield Solar project in Californa, with both projects being substantially constructed in 2014 and expected to reach commercial operation early in 2015. In November, we announced a further 10 MW expansion of our Bakersfield Solar Project in California, an important commitment to our growing solar portfolio.

Also in 2014, we became the sole owner of three wind projects in the United States, which added 160 MW of net generation capacity to our existing wind generation portfolio. With 100% ownership, we expect the investment to contribute accretive, low risk earnings and cash flow to our bottom line.

Additional progress was made in advancing our pipeline of development-phase projects, which is the foundation of our medium term growth. In September, we announced our commitment to the construction-stage 200 MW Odell Wind Project in Minnesota, which is scheduled to be constructed in late 2015.

Distribution

2014 saw the successful completion of our Distribution group's $175 million capital investment program into the existing portfolio of regulated distribution utilities.

We continued the expansion of our water distribution operations in the United States with the agreement to acquire Park Water Company. Park Water owns and operates three regulated water utilities in Southern California and Western Montana and its acquisition will add 74,000 connections to our existing service base of nearly half a million customers in the latter half of 2015. Through the year, we validated our ability to expand our service territory footprint with the acquisition of New Hampshire Gas, a gas distribution utility that serves more than 1,200 customers and the Whitehall water system, serving approximately 4,000 customers in Arkansas.

We also succeeded in finalizing a number of rate cases in our various jurisdictions, including New Hampshire, Georgia, and Arizona, which will provide over $15 million in additional revenues beginning in 2015.

The core proposition of our Distribution business group is providing local, responsive and caring service to our customers. We are committed to local decision making and priority setting in the communities in which we operate. In 2014, we reaffirmed our commitment to resource conservation, infrastructure improvements and overall customer service, and we will continue this focus into 2015 and beyond.

Transmission

This past year marked the formal creation of our Transmission group, focused on originating and developing investment opportunities within the electrical transmission and natural gas pipeline sectors. With the launch of this new business group, Algonquin Power & Utilities is a diversified, connected utility company operating across the spectrum from generation to transmission and, ultimately, distribution.

The formation of our Transmission group was confirmed with our November announcement of a development partnership in Kinder Morgan's proposed Northeast Energy Direct natural gas pipeline project. The pipeline's resource will be contracted with local distribution utilities and other customers to ease supply constraints in the northeast United States and help ensure reliable delivery to the power-generation grid. This new pipeline not only provides a valued service and resource to the gas constrained region of the New England states, but also provides Algonquin Power & Utilities with another avenue for growth.

Financial Success

We believe that the financial success highlighted throughout this annual report demonstrates our ability to effectively execute on our financial goals and growth strategies. We are pleased to report that in 2014 we realized a total shareholder return of 37%. 2014 was a year of continued growth, as annual revenues grew by 40%, our asset base expanded by 18%, and our market capitalization increased 52%, as compared to 2013 results.

In 2014, we were successful in positioning the company well with respect to our 2015 capital program. Capital sourcing initiatives for 2014 saw the issuance of over $370 million in equity financings, a $100 million preferred share offering, and $200 million in 4.65% senior unsecured debentures early in the year.

Our financial success was validated by the Board of Directors' decision in August to approve a 12.4% dividend increase from CDN $0.34 to U.S. $0.35 per common share. The strategic decision to change the dividend payout to U.S. dollars aimed to assume consistency with the company's predominantly U.S.-generated cash flows.

Looking ahead

As always, we will continue to seek new opportunities and execute on our growth plans, fulfilling our commitment to create long term value for our shareholders through ongoing investments in our three business groups – Generation, Transmission, and Distribution.

For our Generation group, with commercial operation at our 20 MW Bakersfield, California solar facility and our 24 MW Morse, Saskatchewan wind project expected to be behind us shortly, 2015 will see continued commitment to growing our solar and wind generation portfolios and we will focus on advancing our existing pipeline of growth projects as well as sourcing new renewable power projects to further diversify our portfolio.

Within our Distribution group, we are expecting the completion of the Park Water acquisition in the second half of 2015 and look forward to welcoming

Park Water employees to our growing Liberty Utilities family. Additionally we will remain focused on ensuring that prudent and necessary capital investments are made to ensure the safe and reliable operation of our utilities well into the future.

Our Transmission business will be focused on moving forward with the regulatory activities associated with the Kinder Morgan pipeline venture and continuing the construction of our recently approved transmission project dedicating to serving our California electric utility. We will also focus on originating additional natural gas pipeline projects and electrical transmission investment opportunities to add to our portfolio.

As a growth focused Generation, Transmission, and Distribution utility company with over $2.7 billion in investment potential over the next few years, we will continue to deliver predictable growth.

Thank You

We would like to take this time to acknowledge and thank you, our shareholders, for your tremendous support and continued confidence in our organization. As a growth focused Generation, Transmission, and Distribution utility company with over $2.7 billion in investment potential over the next few years, we will continue to deliver predictable growth over the short, medium, and long-term. We sincerely appreciate your commitment to us and trust that 2014 has been a mutually rewarding and encouraging year. We remain devoted to creating long-term value and sector-leading returns for your investment and look forward to sharing in the successes that lie ahead.

Sincerely,

Ian Robertson
Chief Executive Officer

Ken Moore
Chairman of the Board of Directors

ALGONQUIN
Power & Utilities Corp.

Management Discussion & Analysis

(All monetary amounts are in thousands of Canadian dollars, except per share amounts or where otherwise noted.)

Management of Algonquin Power & Utilities Corp. ("APUC" or the "Company") has prepared the following discussion and analysis to provide information to assist its shareholders' understanding of the financial results for the three and twelve months ended December 31, 2014. The Management Discussion & Analysis ("MD&A") should be read in conjunction with APUC's audited consolidated financial statements for the years ended December 31, 2014 and 2013. This material is available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com. Additional information about APUC, including the most recent Annual Information Form ("AIF") can be found on SEDAR at www.sedar.com.

This MD&A is based on information available to management as of March 15, 2015.

Caution concerning forward-looking statements and non-GAAP Measures

Forward-looking statements

Certain statements included herein contain forward-looking information within the meaning of certain securities laws. These statements reflect the views of APUC with respect to future events, based upon assumptions relating to, among others, the performance of APUC's assets and the business, interest and exchange rates, commodity market prices, and the financial and regulatory climate in which it operates. These forward looking statements include, among others, statements with respect to the expected performance of APUC, its future plans and its dividends to shareholders. Statements containing expressions such as "anticipates", "believes", "continues", "could", "expect", "estimates", "intends", "may", "outlook", "plans", "project", "strives", "will", and similar expressions generally constitute forward-looking statements.

Since forward-looking statements relate to future events and conditions, by their very nature they require APUC to make assumptions and involve inherent risks and uncertainties. APUC cautions that although it believes its assumptions are reasonable in the circumstances, these risks and uncertainties give rise to the possibility that actual results may differ materially from the expectations set out in the forward-looking statements. Material risk factors include the impact of movements in exchange rates and interest rates; the effects of changes in environmental and other laws and regulatory policy applicable to the energy and utilities sectors; decisions taken by regulators on monetary policy; and the state of the Canadian and the United States ("U.S.") economies and accompanying business climate. APUC cautions that this list is not exhaustive, and other factors could adversely affect results. Given these risks, undue reliance should not be placed on these forward-looking statements. In addition, such statements are made based on information available and expectations as of the date of this MD&A and such expectations may change after this date. APUC reviews material forward-looking information it has presented, not less frequently than on a quarterly basis. APUC is not obligated to nor does it intend to update or revise any forward-looking statements, whether as a result of new information, future developments or otherwise, except as required by law.

Non-GAAP Financial Measures

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

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

Adjusted net earnings

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

Adjusted funds from operations

Adjusted funds from operations is a non-GAAP measure used by investors to compare cash flows from operating activities without the effects of certain volatile items that generally have no current economic impact or items such as acquisition expenses and are viewed as not directly related to a company's operating performance. Cash flows from operating activities of APUC can be impacted positively or negatively by changes in working capital balances, acquisition expenses, litigation expenses cash provided or used in discontinued operations. Adjusted weighted average shares outstanding represents weighted average shares outstanding adjusted to remove the dilution effect related to shares issued in advance of funding requirements. APUC uses adjusted funds from operations to assess its performance without the effects of (as applicable) changes in working capital balances, acquisition expenses, litigation expenses, cash provided or used in discontinued operations and other typically non-recurring items affecting cash from operations as these are not reflective of the long-term performance of the underlying businesses of APUC. APUC believes that analysis and presentation of funds from operations on this basis will enhance an investor's understanding of the operating performance of its businesses. It is not intended to be representative of cash flows from operating activities as determined in accordance with GAAP.

Net energy sales

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

Net utility sales

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

Overview and Business Strategy

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

APUC's current quarterly dividend to shareholders is U.S. $0.0875 per share or U.S. $0.35 per share per annum. Based on exchange rates as at December 31, 2014, the quarterly dividend is equivalent to CAD $0.10 per share or CAD $0.41 per share per annum. APUC believes its annual dividend payout allows for both an immediate return on investment for shareholders and retention of sufficient cash within APUC to fund growth opportunities and mitigate the impact of fluctuations in foreign exchange rates. Further increases in the level of dividends paid by APUC are at the discretion of the APUC Board of Directors (the "Board") with dividend levels being reviewed periodically by the Board in the context of cash available for distribution and earnings together with an assessment of the growth prospects available to APUC. APUC strives to achieve its results in the context of a moderate risk profile consistent with top-quartile North American power and utility operations.

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

Generation Business Group

The Generation Group generates and sells electrical energy produced by its diverse portfolio of non-regulated renewable power generation and clean energy power generation facilities located across North America. The 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 Generation Group owns or has interests in hydroelectric, wind, and solar facilities with a combined generating capacity of approximately 120 MW, 675 MW, and 10MW, respectively. Approximately 83% of the electrical output from the hydroelectric, wind and solar generating facilities is sold pursuant to long term contractual arrangements which have a weighted average remaining contract life of 14 years.

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

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

Distribution Business Group

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

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

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

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

Transmission Business Group

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

Major Highlights

2014 Corporate Highlights

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

APUC has completed several acquisitions and advanced on other initiatives including its power development projects that have raised the growth profile for APUC's earnings and cash flows which in turn supports an increase in the dividend to shareholders. As a result, on August 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 per annum, 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. APUC's consolidated assets are approximately 80% based in the U.S. and generate approximately 77% of its underlying cash flows.

Management believes that the increase in dividend is consistent with APUC's stated strategy of delivering total shareholder return comprised of attractive current dividend yield and capital appreciation founded on increased earnings and cash flows.

Strengthening the Balance Sheet and Poising for Continued Growth

Issuance of $100 million Preferred Shares

On March 5, 2014, APUC issued 4.0 million cumulative rate reset preferred shares, Series D at a price of $25 per share, for aggregate gross proceeds of $100.0 million. The Series D shares will 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 revolving credit facilities, and for general corporate purposes.

Issuance of Common Shares

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

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 7,865,170 subscription receipts ("Subscription Receipts") of APUC at a price of $8.90 per Subscription Receipt, for a subscription price of $70.0 million.

On September 26, 2014, as a result of the Underwriters exercising the Over-Allotment Option, an additional 843,000 Subscription Receipts were issued to Emera at a price of $8.90 per Subscription Receipt, for an aggregate subscription price 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 a subscription price of $33.0 million.

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

2014 Generation Group Highlights

Acquisition of Odell Wind Project

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

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

Completion of Cornwall Solar Project

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

Completion of St. Damase Wind Project

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

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

Significant Progress on Power Development Projects

During 2014, the Generation Group made significant progress advancing several of its development projects. Construction on the Bakersfield I Solar Project near Bakersfield, California began in the second quarter of 2014 and was placed in service on December 30, 2014. Final construction efforts continue with the project expected to reach full commercial operations in the first quarter of 2015.

Construction of the Morse Wind Project near Morse, Saskatchewan is in its final stages. Installation of access roads and foundations are complete, turbine delivery commenced in January 2015, and seven of ten turbines have been erected. The project is expected to be operational by March 31, 2015.

Expansion of Bakersfield I Solar Project

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

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

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

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

On March 31, 2014, the Generation Group acquired from Gamesa Wind US, LLC ("Gamesa") the remaining 40% of the Class B partnership units of the entity which owns a three facility 400 MW wind power portfolio (the "U.S. Wind Portfolio") in the United States for total consideration of approximately U.S. $115.0 million. As a result of the transaction, the Generation Group now owns 100% of the Class B partnership units of the entity that owns the U.S. Wind Portfolio.

The Generation Group originally acquired 60% of the Class B units of the entity which owns the U.S. Wind Portfolio in 2012. The U.S. Wind Portfolio is a 400 MW wind portfolio consisting of three facilities: Minonk (200MW), Senate (150MW), and Sandy Ridge (50MW) located in the states of Illinois, Texas, and Pennsylvania, respectively. Gamesa will continue to provide operations, warranty and maintenance services for the wind turbines and balance of plant facilities under 20 year contracts.

$200 million Senior Unsecured Debentures

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

Net proceeds were used towards financing the acquisition of the remaining 40% ownership interest in its U.S. Wind Portfolio, to reduce amounts outstanding on project debt related to its Shady Oaks Wind Facility, to reduce amounts outstanding under the Generation Group's senior unsecured revolving credit facility ("Generation Credit Facility"), and for general corporate purposes.

Additional Liquidity

On July 31, 2014, the Generation Group increased the credit available under the Generation Credit Facility to $350 million from $200 million. The larger credit facility will be used to provide additional liquidity in support of the group's $1,225.0 million development portfolio to be completed over the next three years. In addition to the larger size, the maturity of the facility has been extended from three to four years and now extends until July 31, 2018.

2014 Distribution Group Highlights

Agreement to acquire Park Water System

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

Total consideration for the utility purchase is expected to be approximately U.S. $327 million, which includes the assumption of approximately U.S. $77 million of existing long-term utility debt. The acquisition will maintain APUC's strategic business mix and further enhance its investment grade consolidated capital structure.

Acquisition of White Hall Water System

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

Acquisition of New Hampshire Gas

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

Successful Rate Case Outcomes

A core strategy of the Distribution Group is to ensure appropriate return on the rate base at its various utility systems. The group has successfully completed several rate cases throughout 2014, representing a cumulative annual revenue increase of approximately U.S. $29.1 million. The full annualized impact of these rate cases will be realized in 2015. Further detail on the various regulatory proceedings of the Distribution Group can be found under Regulatory Proceedings.

2014 Transmission Group Highlights

Agreement to acquire interest in Natural Gas Transmission Pipeline

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

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

2014 Annual Results From Operations

As outlined, APUC has continued to advance growth initiatives throughout 2014 that had a positive contribution to the annual results. In addition, the results now reflect full year operations from the gas and water systems acquisitions completed by the Distribution Group in 2013.

Key Selected Annual Financial Information

(all dollar amounts in $ millions except per share information)	Year ended December 31 2014	2013	2012
Revenue	**$ 943.6**	$ 675.3	$ 348.8
Adjusted EBITDA [1]	**290.6**	228.1	88.1
Cash provided by operating activities	**192.7**	98.9	63.0
Adjusted funds from operations[1]	**206.5**	154.9	66.8
Net earnings attributable to Shareholders from continuing operations	**77.8**	62.3	13.5
Net earnings attributable to Shareholders	**75.7**	20.3	14.5
Adjusted net earnings [1]	**88.4**	59.5	18.9
Dividends declared to Common Shareholders	**82.9**	68.3	50.2
Weighted Average number of common shares outstanding	**213,953,870**	204,350,689	158,304,340
Per share			
Basic net earnings from continuing operations	**$ 0.32**	$ 0.28	$ 0.08
Basic net earnings	**$ 0.31**	$ 0.07	$ 0.09
Adjusted net earnings [1, 2]	**$ 0.37**	$ 0.26	$ 0.11
Diluted net earnings	**$ 0.31**	$ 0.07	$ 0.09
Cash provided by operating activities [1, 2]	**$ 0.90**	$ 0.48	$ 0.40
Adjusted funds from operations[1, 2]	**$ 0.92**	$ 0.73	$ 0.42
Dividends declared to Common Shareholders	**$ 0.37**	$ 0.33	$ 0.30
Total assets	**4,113.7**	3,476.5	2,779.0
Long term liabilities [3]	**1,280.0**	1,255.6	770.8

1 Non-GAAP Financial Measures

2 APUC uses per share adjusted net earnings, cash provided by operating activities and adjusted funds from operations to enhance assessment and understanding of the performance of APUC.

3 Includes long-term liabilities and current portion of long-term liabilities

For the year ended December 31, 2014, APUC experienced an average U.S. exchange rate of approximately $1.1049 as compared to $1.0300 in the same period in 2013. As such, any year over year variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's Canadian dollar reporting currency.

For the year ended December 31, 2014, APUC reported total revenue of $943.6 million as compared to $675.3 million during the same period in 2013, an increase of $268.3 million or 39.7%. The major factors resulting in the increase in APUC revenue for the year ended December 31, 2014 as compared to the corresponding period in 2013 are set out as follows:

(all dollar amounts in $ millions)		Year to date December 31, 2014
Comparative Prior Period Revenue	$	675.3
Significant Changes:		
Generation Group		
Renewable:		
Increased wind resources net of hedge settlements at the Minonk, Senate, and Sandy Ridge Wind Facilities		1.1
Higher realized prices from Renewable Energy Credits generated from the U.S. Wind Facilities		4.8
Start of commercial operations of the Cornwall Solar Facility		5.5
Increased customer load in the Maritime region		1.7
Thermal:		
Increased average prices at the Windsor Locks and Sanger Thermal Facilities		5.3
Increased sale of Renewable Energy Credits generated at the Windsor Locks Thermal Facility		0.7
Distribution Group		
Natural Gas Systems - Increased revenue due to acquisition of the Peach State Gas System (U.S. $32.9 million), and the New England Gas System (U.S. $76.3 million)		108.2
Natural Gas Systems - Revenue increase due to higher customer demand as a result of colder than average weather at the EnergyNorth and Midstates Natural Gas Systems		35.2
Electric Systems - Revenue increase at the electric systems predominantly due to higher customer demand at the Granite State Electric System		13.8
Rate Cases – Revenue increase due to higher electricity rates at the Granite State Electric System (U.S. $11.8 million) and Peach State Gas System (U.S. $5.5 million)		17.2
Water and Waste Systems – Revenue increase due to the increased customer demand		3.5
Increase due to acquisition of New England Gas System's water heater rental service (U.S. $2.8 million) and increased revenues at Peach State Gas System's Fort Benning operation (U.S. $1.0 million)		3.8
Impact of the stronger U.S. dollar		68.4
Other		(0.9)
Current Period Revenue	$	943.6

A more detailed discussion of these factors is presented within the business unit analysis.

Adjusted EBITDA in the year ended December 31, 2014 totalled $290.6 million as compared to $228.1 million during the same period in 2013, an increase of $62.5 million or 27.4%. The increase in Adjusted EBITDA was primarily due to acquisitions completed in 2014 and 2013, impact of rate case settlements, increased customer demand for Gas distribution, and the increase in REC transactions. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see Non-GAAP Performance Measures).

For the year ended December 31, 2014, net earnings from continuing operations attributable to Shareholders totalled $77.8 million as compared to $62.3 million during the same period in 2013, an increase of $15.5 million. The increase was due to $63.7 million in increased earnings from operating facilities, $0.5 million in increased foreign exchange gains, and $1.2 million due to a gain on sale of assets, as compared to the same period in 2013. These items were partially offset by $18.0 million in increased depreciation and amortization expenses, $11.2 million in increased administration charges, $9.0 million in increased interest expense, $0.4 million in increased acquisition costs, $8.5 million in increased write-downs on notes receivable and property, plant, and equipment, $6.6 million in increased loss from derivative instruments, $11.4 million in increased allocations of earnings to non-controlling interests, and $7.7 million in increased income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses),* as compared to the same period in 2013.

For the year ended December 31, 2014, net earnings (including discontinued operations) attributable to Shareholders totalled $75.7 million as compared to $20.3 million during the same period in 2013, an increase of $55.4 million. Net earnings per share totalled $0.31 for the year ended December 31, 2014, as compared to $0.07 during the same period in 2013.

During the year ended December 31, 2014, cash provided by operating activities totalled $192.7 million or $0.90 per share as compared to cash provided by operating activities of $98.9 million, or $0.48 per share during the same period in 2013. During the year ended December 31, 2014, adjusted funds from operations, a non-GAAP measure, totalled $206.5 million or $0.92 per share as compared to adjusted funds from operations of $154.9 million, or $0.73 per share during the same period in 2013, an increase of $51.6 million.

Cash per share provided by operating activities and per share adjusted funds from operations are non-GAAP measures. Per share cash provided by operating activities and per share adjusted funds from operations are not substitute measures of performance for earnings per share. Amounts represented by per share cash provided by operating activities and per share adjusted funds from operations do not represent amounts available for distribution to shareholders and should be considered in light of various charges and claims against APUC.

2014 Fourth Quarter Results From Operations

Key Selected Fourth Quarter Financial Information

	Three months ended December 31	
(all dollar amounts in $ millions except per share information)	2014	2013
Revenue	**$ 259.3**	$ 205.3
Adjusted EBITDA [1]	**84.3**	68.5
Cash provided by operating activities	**96.5**	28.4
Adjusted funds from operations[1]	**65.9**	46.0
Net earnings attributable to Shareholders from continuing operations	**33.1**	19.8
Net earnings attributable to Shareholders	**31.6**	13.2
Adjusted net earnings[1]	**35.2**	18.8
Dividends declared to Common Shareholders	**25.4**	17.6
Weighted Average number of common shares outstanding	**230,664,583**	206,219,121
Per share		
Basic net earnings/(loss) from continuing operations	**$ 0.13**	$ 0.09
Basic net earnings/(loss)	**$ 0.13**	$ 0.06
Adjusted net earnings[1, 2]	**$ 0.14**	$ 0.08
Diluted net earnings/(loss)	**$ 0.12**	$ 0.06
Cash provided by operating activities [1, 2]	**$ 0.42**	$ 0.14
Adjusted funds from operations[1, 2]	**$ 0.27**	$ 0.22
Dividends declared to Common Shareholders	**$ 0.10**	$ 0.09

1 Non-GAAP Financial Measures

2 APUC uses per share adjusted net earnings, cash provided by operating activities and adjusted funds from operations to enhance assessment and understanding of the performance of APUC.

For the three months ended December 31, 2014, APUC experienced an average U.S. exchange rate of approximately $1.136 as compared to $1.050 in the same period in 2013. As such, any quarter over quarter variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's reporting currency.

For the three months ended December 31, 2014, APUC reported total revenue of $259.3 million as compared to $205.3 million during the same period in 2013, an increase of $54.0 million. The major factors resulting in the increase in APUC revenue in the three months ended December 31, 2014 as compared to the corresponding period in 2013 are set out as follows:

(all dollar amounts in $ millions)		Quarter ended December 31, 2014
Comparative Prior Period Revenue	$	205.3
Significant Changes:		
Generation Group		
Renewable:		
Effect of hydrology resource compared to comparable period in prior year		1.6
Increased wind resources net of hedge settlements at the Minonk, Senate, and Sandy Ridge Wind Facilities		1.2
Higher realized prices from Renewable Energy Credits generated from the U.S. Wind Facilities		1.1
Start of commercial operations of the Cornwall Solar Facility		0.7
Decreased sales due to reduced retail customer load at the Maritime region		(0.9)
Distribution Group		
Increased revenue due to acquisition of the New England Gas System		10.5
Electric Systems - Revenue increase at the electric systems predominantly due to higher customer demand at the Granite State Electric System		4.3
Natural Gas Systems - Revenue increase due to higher customer demand as a result of colder than average weather at the EnergyNorth, Midstates, and Peach State Natural Gas Systems		8.5
Rate Cases – Revenue increase due to higher electricity rates at the Granite State Electric System (U.S. $1.6 million) and Peach State Gas System (U.S. $2.2 million)		3.8
Water and Waste Systems – Revenue increase due to the increased customer demand		1.1
Increase due to acquisition of New England Gas System's water heater rental service (U.S. $0.8 million) and increased revenues at Peach State Gas System's Fort Benning operation (U.S. $1.0 million)		1.8
Impact of the stronger U.S. dollar		21.2
Other		(0.9)
Current Period Revenue	$	259.3

A more detailed discussion of these factors is presented within the business unit analysis.

Adjusted EBITDA in the three months ended December 31, 2014 totalled $84.3 million as compared to $68.5 million during the same period in 2013, an increase of $15.8 million or 23.1%. The increase in Adjusted EBITDA was primarily due to acquisitions completed in December 2013, impact of rate case settlements, increased hydrology and wind resources, and increase customer demand at the EnergyNorth and Midstates Gas Systems. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see Non-GAAP Performance Measures).

For the three months ended December 31, 2014, net earnings attributable to Shareholders from continued operations totalled $33.1 million as compared to $19.8 million during the same period in 2013, an increase of $13.3 million. The increase was due to $20.3 million in increased earnings from operating facilities, $1.5 million in decreased income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses)*, $0.3 million in decreased interest expense, $0.7 million due to a gain on sale of assets, and $4.9 million in increased allocation of earnings to non-controlling interests, as compared to the same period in 2013. These items were partially offset by $2.1 million in increased depreciation and amortization expenses, $5.4 million in increased administration charges, $0.4 million in decreased foreign exchange gains, $0.5 million in decreased interest and dividend income, $1.0 million in increased acquisition costs, $0.3 million in increased write-downs on notes receivable and property, plant, and equipment, and $4.7 million in decreased gains from derivative instruments.

For the three months ended December 31, 2014, net earnings (including discontinued operations) attributable to Shareholders totalled $31.6 million as compared to net earnings attributable to Shareholders of $13.2 million during the same period in 2013, an increase of $18.4 million. Net earnings per share totalled $0.13 for the three months ended December 31, 2014, as compared to net earnings per share of $0.06 during the same period in 2013.

During the three months ended December 31, 2014, cash provided by operating activities totalled $96.5 million or $0.42 per share as compared to cash provided by operating activities of $28.4 million, or $0.14 per share during the same period in 2013. During the three months ended December 31, 2014, adjusted funds from operations totalled $65.9 million or $0.27 per share as compared to adjusted funds from operations of $46.0 million, or $0.22 per share during the same period in 2013. The change in adjusted funds from operations in the three months ended December 31, 2014, is primarily due to increased earnings from operations, as compared to the same period in 2013.

Cash per share provided by operating activities and per share adjusted funds from operations are non-GAAP measures. Per share cash provided by operating activities and per share adjusted funds from operations are not substitute measures of performance for earnings per share. Amounts represented by per share cash provided by operating activities and per share adjusted funds from operations do not represent amounts available for distribution to shareholders and should be considered in light of various charges and claims against APUC.

GENERATION BUSINESS GROUP

Renewable Energy Division

	Three months ended December 31			Year ended December 31		
	Long Term Average Resource	2014	2013	Long Term Average Resource	2014	2013
Performance (GW-hrs sold)						
Hydro Facilities:						
Maritime Region	45.8	38.0	37.9	177.8	146.2	203.1
Quebec Region[1]	72.8	72.3	68.1	274.9	259.4	277.7
Ontario Region[2]	33.8	38.7	39.3	139.8	144.5	90.4
Western Region	12.6	13.4	12.1	65.0	74.1	66.6
	165.0	162.4	157.4	657.5	624.2	637.8
Wind Facilities:						
St. Damase[3]	6.7	4.7	—	6.7	4.7	—
St. Leon	121.4	119.9	116.5	430.2	441.4	398.0
Red Lily[4]	24.1	23.8	22.8	88.5	87.7	79.0
Sandy Ridge	43.6	46.7	38.7	158.3	149.0	138.7
Minonk	195.8	195.4	182.8	673.3	648.5	621.8
Senate	140.0	139.0	133.8	520.4	537.6	524.5
Shady Oaks	100.4	92.2	88.7	364.0	339.9	317.1
	632.0	621.7	583.3	2,241.4	2,208.8	2,079.1
Solar Facilities:						
Cornwall	2.2	1.8	—	11.8	12.8	—
Total Performance	799.2	785.9	740.7	2,910.7	2,845.8	2,716.9

1 The Generation Group's Donnacona Hydro Facility was offline during the second half of 2014. Insurance proceeds were received to compensate for lost revenue.

2 The Generation Group's Long Sault hydro facility was offline during most of the first nine months of 2013. Insurance proceeds were received to compensate for lost revenue.

3 The St Damase Wind Facility achieved commercial operation on December 2, 2014. Long term average resource and production represent production from December 2 to December 31, 2014.

4 APUC does not consolidate the operating results from this facility in its financial statements. Production from the facility is included as APUC manages the facility under contract and has an option to acquire a 75% equity interest in the facility in 2016.

For the twelve months ended December 31, 2014, the Renewable Energy Division generated 2,845.8 GW-hrs of electricity. This level of production represents sufficient energy to supply the equivalent of 210,800 homes on an annualized basis with renewable power. As a result of renewable energy production, the equivalent of 2,086,900 tons of CO_2 gas was prevented from entering the atmosphere.

	Three months ended December 31		Year ended December 31	
(all dollar amounts in $ millions)	2014	2013	2014	2013
Revenue[1]				
Hydro Sales	$ 16.8	$ 15.9	$ 65.1	$ 61.9
Wind	26.9	24.5	88.8	83.8
Solar	0.7	—	5.5	—
Total Revenue	**$ 44.4**	$ 40.4	**$ 159.4**	$ 145.7
Less:				
Cost of Sales - Energy[2]	(1.5)	(3.8)	(16.7)	(8.7)
Realized gain/(loss) on hedges[3]	(0.2)	0.3	3.6	0.5
Net Energy Sales	**$ 42.7**	$ 36.9	**$ 146.3**	$ 137.5
Renewable Energy Credits ("REC")[4]	4.0	2.6	11.7	5.9
Other Revenue	0.4	0.2	1.6	1.2
Total Net Revenue	**$ 47.1**	$ 39.7	$ 159.6	$ 144.6
Expenses & Other Income				
Operating expenses	(11.0)	(11.2)	(46.1)	(40.3)
Interest and Other income	0.4	0.5	1.7	1.9
HLBV income/(loss)	8.9	6.8	27.2	20.4
Divisional operating profit	**$ 45.4**	$ 35.8	**$ 142.4**	$ 126.6

1 While most of the Generation Group's PPAs include annual rate increases, a change to the weighted average production levels resulting in higher average production from facilities that earn lower energy rates can result in a lower weighted average energy rate earned by the division, as compared to the same period in the prior year.

2 Cost of Sales - Energy consists of energy purchases in the Maritime Region to manage the energy sales from the Tinker Facility which is sold to retail and industrial customers under multi-year contracts.

3 See financial statements note 25(b)(iv).

4 Qualifying renewable energy projects receive Renewable Energy Credits (RECs) for the generation and delivery of renewable energy to the power grid. The energy credit certificates represent proof that 1 MW of electricity was generated from an eligible energy source. The RECs can be traded and the owner of the REC can claim to have purchases of renewable energy. REC revenue is recognized only at the time a generated REC unit is matched up with a previously signed REC sales contract with a third party. Generated REC units not immediately available to match against a signed contract are recorded as inventory with the offset recorded as a decrease in operating expenses.

2014 Fourth Quarter Operating Results

For the three months ended December 31, 2014, the hydro facilities generated 162.4 GW-hrs of electricity, as compared to 157.4 GW-hrs produced in the same period in 2013, an increase of 3.2%. The increased generation is largely attributable to significantly better hydrology in Quebec that more than offset the Donnacona Hydro Facility being offline throughout the quarter. See the "Quebec Dam Safety Act" section for a further discussion on the Donnacona Hydro Facility.

During the three months ended December 31, 2014, the hydro facilities generated electricity equal to 98.4% of long-term projected average resources as compared to 95.2% during the same period in 2013. During the three months ended December 31, 2014, the Ontario and Western Hydro regions achieved production greater than their long-term averages. The Quebec region was below the long term average due to Donnacona being offline. Excluding Donnacona, the Quebec region would have achieved 108% of the LTAR.

For the three months ended December 31, 2014, revenue from the hydro facilities totalled $16.8 million as compared to $15.9 million during the same period in 2013, an increase of $0.9 million. Revenue from generation at the hydro facilities located in the Quebec region increased by $1.4 million, as compared to the same period in 2013. The increase is attributed to more favorable hydrology in the Quebec region. This was offset by decreased revenues in the Maritime region of $0.7 million, primarily due to decreased customer load served. Revenue in the Maritime region primarily consists of the sale of the off-take from the Tinker Hydro Facility through wholesale deliveries to local electric utilities, retail sales to commercial and industrial customers in Northern Maine, merchant sales of production in excess of committed customer deliveries from the Tinker Hydro Facility, and other revenue.

For the three months ended December 31, 2014, energy purchase costs at the Maritime region totalled $1.5 million, as compared to $3.8 million during the same period in 2013, a decrease of $2.3 million. The decrease in the energy purchase costs for the three months ended December 31, 2014 were primarily due to decreased retail customer load served in the quarter requiring reduced energy purchases from the market as the Maritime region was able to generate sufficient energy to meet its retail demand. During this period, approximately 21.4 GW-hrs of energy was purchased at market and fixed rates averaging U.S. $61 per MW-hr.

During the three months ended December 31, 2014, the Maritime region generated approximately 69% of the load required to service its customers, as compared to 44% in the same period in 2013. To mitigate the risk of higher average energy prices, certain power hedges are entered into as part of risk mitigation strategies. For the three months ended December 31, 2014, $0.2 million was realized in connection with these hedges and is recorded as a realized gain on derivative financial instruments in the financial statements.

For the three months ended December 31, 2014, the wind facilities produced 621.7 GW-hrs of electricity, as compared to 583.3 GW-hrs produced in the same period in 2013, an increase of 6.6%. The higher generation was a result of increased wind resources at all sites and the start of production at the newest facility, the St. Damase Wind Facility, which achieved COD on December 2, 2014. The St. Damase wind facility generated 4.7 GW-hrs.

During the three months ended December 31, 2014, the wind facilities (excluding the St. Damase Wind Facility) generated electricity equal to 98.4% of long-term projected average resources, as compared to 93.3% during the same period in 2013, due to variability in the wind resource.

For the three months ended December 31, 2014, revenue from the wind facilities totalled $26.9 million as compared to $24.5 million during the same period in 2013, an increase of $2.4 million. Revenue increases were evident at all wind facilities due mainly to the 38.4 GW/h increase in production due to an increase in wind resources, as compared to the same period last year. As a result, revenues from the Generation Group's Canadian wind facilities increased $0.8 million, while the U.S. wind facilities increased $1.9 million, as compared to the same period last year. These gains were partly offset by $0.3 million in hedge settlements under the Minonk, Senate and Sandy Ridge Wind Facilities' power hedges.

For the three months ended December 31, 2014, REC revenue totalled $4.0 million, as compared to $2.6 million in the same period in 2013, an increase of $1.4 million, primarily attributed to increased market pricing in all regions with the PJM region having the largest impact. The increase in market pricing is largely caused by the annually increasing renewable requirement of the RPS (Renewable Portfolio Standard) outpacing the increase in supply of available RECs. REC units are generated at a ratio of one REC unit per one MW-hr generated and are sold in the market in which the REC is generated. For the three months ended December 31, 2014, REC units and related revenues were generated at the Sandy Ridge, Minonk, Senate, and Shady Oaks Wind Facilities.

During the three months ended December 31, 2014, the Generation Group's solar facility located in Ontario had its third full quarter of operations generating 1.8 GW-hrs of electricity, which is equal to 18.2% below long-term average resources. The facility reached commercial operation on March 27, 2014 and has a 20 year FIT PPA with the Ontario Power Authority.

Revenue from generation at the Generation Group's new solar facility located in Cornwall, Ontario totalled $0.7 million for the period. As commercial operation was achieved late in the first quarter of 2014, there is no comparative data from the previous year.

For the three months ended December 31, 2014, operating expenses excluding energy purchases totalled $11.0 million, as compared to $11.2 million during the same period in 2013, a decrease of $0.2 million. The decrease was primarily attributable to greater inventorying of REC costs at the Senate Wind facility partly offset by operating costs at the new Cornwall Solar Facility.

The Red Lily I Wind Facility located in Saskatchewan produced 23.8 GW-hrs of electricity for the three months ended December 31, 2014. The Generation Group's economic return from its investment in Red Lily currently comes in the form of interest payments, fees and other charges and is not reflected in revenue from energy sales. Under the terms of the agreements, the Generation Group has the right to exchange these contractual and debt interests in the Red Lily I Wind Facility for a direct 75% equity interest in 2016. For the three months ended December 31, 2014, the Generation Group earned fees of $0.3 million (which is classified as other revenue) and interest income of $0.4 million from the Red Lily I Wind Facility.

For the three months ended December 31, 2014, interest and other income totalled $0.4 million, consistent with the same period in 2013. Interest and other income primarily consist of interest related to the senior and subordinated debt interest in Red Lily I Wind Facility. This amount is included as part of the Generation Group's earnings from its investment in the Red Lily I Wind Facility, as discussed above.

For the three months ended December 31, 2014, the value of net tax attributes generated amounted to an approximate HLBV income of $8.9 million, an increase of $2.1 million compared to the prior year. The increase was attributable to increased production, a stronger U.S. dollar exchange rate, and the reduced economic interest in the projects attributable to tax equity.

For the three months ended December 31, 2014, the Renewable Energy Division's operating profit totalled $45.4 million, as compared to $35.8 million during the same period in 2013, an increase of $9.6 million; $2.5 million of the increase is attributable to the stronger U.S. dollar.

2014 Twelve Month Operating Results

For the twelve months ended December 31, 2014, the hydro facilities generated 624.2 GW-hrs of electricity, as compared to 637.8 GW-hrs produced in the same period in 2013, a decrease of 2.1%. The slight decrease in generation is largely due to a decrease in production in the Maritime region due to lower hydrology in the first 3 quarters of the year, almost completely offset by an increased production in the Ontario region with the Long Sault facility return to service, which was offline for the majority of the first and second quarter of 2013.

During the twelve months ended December 31, 2014, the hydro facilities generated electricity equal to 94.9% of long-term projected average resources, as compared to 103.4% during the same period in 2013. During the twelve months ended December 31, 2014, the Ontario and Western Hydro regions achieved production above their long-term averages. The Quebec and Maritime regions were below the long term average production. Had the Quebec region's Donnacona facility been on line, the region would have achieved 102% of the long term average hydrological resource.

For the twelve months ended December 31, 2014, revenue from the hydro facilities totalled $65.1 million, as compared to $61.9 million during the same period in 2013, an increase of $3.2 million. Revenue from generation in the Ontario region increased by $0.7 million due to the Long Sault Hydro Facility being back on-line for the full year 2014. The Quebec and Western regions experienced a decrease of $0.3 million and $0.7 million, respectively. The decrease in the Quebec region is primarily due to the Donnacona Hydro Facility being offline, while the decrease in the Western region is primarily due to lower market pricing on the unhedged portion of the production. The increase in production at the Western region caused the market exposed production amount to increase 8% while the weighted average market price fell by more than 50%. Revenue from the Maritime region increased $3.5 million, primarily due to increased retail customer load served.

For the twelve months ended December 31, 2014, energy purchases totalled $16.7 million, as compared to $8.7 million during the same period in 2013, an increase of $8.0 million. Increased energy purchase costs for the twelve months ended December 31, 2014 were primarily due to lower hydrology in the Maritime region in the first half of the year, which required increased energy purchases from external suppliers at higher average prices. During this period, purchases of approximately 166.0 GW-hrs of energy at market and fixed rates averaging U.S. $91 per MW-hr were made. During the twelve months ended December 31, 2014, the Maritime region generated approximately 46% of the load required to service its customers, as compared to 67% in the same period in 2013. To mitigate the risk of higher average energy prices, the Maritime region had previously entered into certain power hedges as part of its risk mitigation strategies. For the twelve months ended December 31, 2014, $3.6 million was realized in connection with these hedges and is recorded as a realized gain on derivative financial instruments on the Consolidated Statement of Operations.

For the twelve months ended December 31, 2014, the wind facilities produced 2,208.8 GW-hrs of electricity, as compared to 2,079.1 GW-hrs produced in the same period in 2013, an increase of 6.2%. The increased generation was a result of stronger wind resources at the St. Leon, Minonk, Sandy Ridge, and Senate Wind Facility along with the St. Damase Wind Facility which achieved COD on December 2, 2014.

During the twelve months ended December 31, 2014, the wind facilities generated electricity equal to 98.5% of long-term projected average resources, as compared to 93.1% during the same period in 2013. For the twelve months ended December 31, 2014, revenue from the wind facilities totalled $88.8 million, as compared to $83.8 million during the same period in 2013, an increase of $5.0 million. The increase in revenue was due primarily to a 129.7 GW/h increase in production from stronger wind resources, as compared to the same period last year. As a result, revenues from the Generation Group's Canadian wind facilities increased $3.5 million, while the U.S. wind facilities increased $1.5 million, net of hedge settlements under the Minonk, Senate and Sandy Ridge Wind Facilities' power hedges.

For the twelve months ended December 31, 2014, REC revenue totalled $11.7 million, as compared to $5.9 million in the same period in 2013, an increase of $5.8 million, primarily a result of increased market pricing and a greater number of RECs generated and sold. REC units are generated at a ratio of one REC unit per one MW-hr generated and are sold in the market in which the REC is generated. For the twelve months ended December 31, 2014, REC units and related revenues were generated at the Sandy Ridge, Minonk, Senate, and Shady Oaks Wind Facilities.

During the twelve months ended December 31, 2014, the Generation Group's solar facility located in Ontario generated 12.8 GW-hrs of electricity, which is equal to 8.5% above long-term average resources from the commercial operation date. The facility reached commercial operation on March 27, 2014 and has a 20 year FIT PPA with the Ontario Power Authority.

Revenue from generation totalled $5.5 million for the period. The facility achieved commercial operation on March 27, 2014 and therefore there is no comparative data from the previous year.

For the twelve months ended December 31, 2014, operating expenses excluding energy purchases totalled $46.1 million, as compared to $40.3 million during the same period in 2013, an increase of $5.8 million. The increase was due to the appreciation of the U.S. dollar, operating costs for Cornwall's first year of operations, and cost of RECs contracted in the first quarter of 2014 but produced in the fourth quarter of 2013.

For the twelve months ended December 31, 2014, interest and other income totalled $1.7 million, as compared to $1.9 million during the same period in 2013. Interest and other income primarily consist of interest related to the senior and subordinated debt interest in Red Lily I Wind Facility. This amount is included as part of the Generation Group's earnings from its investment in Red Lily I Wind Facility, as discussed below.

The Red Lily I Wind Facility located in Saskatchewan produced 87.7 GW-hrs of electricity for the twelve months ended December 31, 2014. The Generation Group's economic return from its investment in Red Lily currently comes in the form of interest payments, fees and other charges and is not reflected in revenue from energy sales. Under the terms of the agreements, the Generation Group has the right to exchange these contractual and debt interests in the Red Lily I Wind Facility for a direct 75% equity interest in 2016. For the twelve months ended December 31, 2014, the Generation Group earned fees of $1.3 million (which is classified as other revenue) and interest income of $1.6 million from the Red Lily I Wind Facility.

Hypothetical Liquidation at Book Value ("HLBV") income represents the value of net tax attributes, primarily related to electricity production generated by the Generation Group in the period from certain of its U.S. wind power generation facilities. The value of net tax attributes generated in the twelve months ended December 31, 2014 amounted to an approximate HLBV income of $27.2 million, as compared to $20.4 million in the prior year. The increase of $6.8 million was primarily a result of a stronger U.S. dollar exchange rate, increased production at all U.S. sites, and a higher income allocation to the Generation Group due to the reduced economic interest of Tax Equity investors in the projects.

For the twelve months ended December 31, 2014, the Renewable Energy Division's operating profit totalled $142.4 million, as compared to $126.6 million during the same period in 2013, an increase of $15.8 million; $3.5 million of the increase is attributable to the stronger U.S. dollar.

GENERATION BUSINESS GROUP

Thermal Energy Division

	Three months ended December 31, 2014			Three months ended December 31, 2013		
	Windsor Locks	Sanger	Total	Windsor Locks	Sanger	Total
Performance (GW-hrs sold)	**26.3**	**35.1**	**61.4**	28.8	35.6	64.4
Performance (steam sales – billion lbs)	**157.3**	**—**	**157.3**	161.3	—	161.3
(all dollar amounts in $ millions)						
Revenue						
Energy/steam sales	**$ 4.7**	**$ 4.3**	**$ 9.0**	$ 4.6	$ 3.9	$ 8.5
Less:						
Cost of Sales – Fuel	**(3.1)**	**(1.9)**	**(5.0)**	(3.1)	(1.5)	(4.6)
Net Energy/Steam Sales	**$ 1.6**	**$ 2.4**	**$ 4.0**	$ 1.5	$ 2.4	$ 3.9
Other Revenue	**0.1**	**0.6**	**0.7**	0.2	0.6	0.8
Total Net Revenue	**$ 1.7**	**$ 3.0**	**$ 4.7**	$ 1.7	$ 3.0	$ 4.7
Expenses						
Operating Expenses	**$ (0.7)**	**$ (1.3)**	**$ (2.0)**	$ (0.9)	$ (1.2)	$ (2.1)
Facility operating profit	**$ 1.0**	**$ 1.7**	**$ 2.7**	$ 0.8	$ 1.8	$ 2.6
Interest and other income			**(0.3)**			0.1
Divisional operating profit			**$ 2.4**			$ 2.7

2014 Fourth Quarter Operating Results

The Generation Group's Sanger and Windsor Locks Thermal Facilities purchase natural gas from different suppliers and at prices based on different regional hubs. As a result, the average landed cost per unit of natural gas will differ between the two facilities in the average landed cost for natural gas and may result in the facilities showing differing costs per unit compared to each other and compared to the same period in the prior year. Total natural gas expense will vary based on the volume of natural gas consumed and the average landed cost of natural gas for each MMBTU.

Production data, revenue and expenses have been adjusted to remove the results of the EFW and BCI Thermal Facilities, which were divested on April 4, 2014 for proceeds approximating the carrying value of the net assets on the Consolidated Balance Sheet of the Company as at March 31, 2014. The results of the EFW and BCI Thermal Facilities for the period up to the date of sale are reported as discontinued operations. See Financial Statement note 17 for details.

For the three months ended December 31, 2014, the Thermal Energy Division's operating profit was $2.4 million, as compared to $2.7 million in the same period in 2013, a decrease of $0.3 million. Operating profit contributions for the three months ended December 31, 2014 were $1.0 million from the Windsor Locks Thermal Facility and $1.7 million from the Sanger Thermal Facility, as compared to $0.8 million and $1.8 million, respectively, during the same period in 2013. Interest and other income for the three months ended December 31, 2014 was a loss of $0.3 million, as compared to income of $0.1 million in the prior period. As a result of the stronger U.S. dollar, operating profit increased by $0.2 million.

Windsor Locks Thermal Facility

For the three months ended December 31, 2014, the Windsor Locks Thermal Facility sold 157.3 billion lbs of steam and 26.3 GW-hrs of electricity, as compared to 161.3 billion lbs of steam and 28.8 GW-hrs of electricity in the comparable period of 2013.

The Windsor Locks Thermal Facility's operating profit was driven by energy/steam sales of $4.7 million (U.S. $4.1 million), as compared to $4.6 million (U.S. $4.4 million) in the same period in 2013. The change in electricity/steam sales is attributed to lower production, but partly offset by a higher average price for gas as a result of the better ISO NE electricity market price. Gas costs for the period were $3.1 million (U.S. $2.7 million), as compared to$3.1 million (U.S. $2.9 million) in the same period in 2013. The change in gas costs is a result of decreased production, partly offset by increases in the average landed cost of natural gas per MMBTU in the quarter, as compared to the same period in 2013.

As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales' (see non-GAAP Financial Measures) as an appropriate measure of the division's results. For the three months ended December 31, 2014, net sales at the Windsor Locks Thermal Facility totalled $1.6 million (U.S. $1.4 million) as compared to $1.5 million (U.S. $1.5 million) in the same period in 2013. This variance was driven by a small increase in revenue, which was largely the result of the stronger US dollar, and a small decrease in gas costs.

Operating expenses excluding fuel costs were $0.7 million (U.S. $0.6 million), as compared to $0.9 million (U.S. $0.8 million) in the same period in 2013. The decrease was primarily due to an increase in inventorying of REC costs vs the same period last year. Generated RECs that have not been sold under a customer contract are recorded as an increase to inventory with an offset booked to operating expense. The Windsor Locks Thermal Facility's resulting net operating income for the three months ended December 31, 2014 was $1.0 million (U.S. $0.9 million), as compared to $0.8 million (U.S. $0.9 million) in the same period in 2013; $0.2 million of the increase is attributable to the stronger U.S. dollar.

Sanger Thermal Facility

For the three months ended December 31, 2014, the Sanger Thermal Facility sold 35.1 GW-hrs of electricity, as compared to 35.6 GW-hrs of electricity in the comparable period of 2013.

For the three months ended December 31, 2014, the Sanger Thermal Facility's operating profit was driven by energy/steam sales of $4.3 million (U.S. $3.8 million), as compared to $3.9 million (U.S. $3.7 million) in the same period in 2013, an increase of $0.4 million. The increase in energy/steam sales is primarily due to an increase in the contract basis differential and passing on higher gas prices to our customer, as compared to the same period in 2013. Capacity revenues remained unchanged at $1.7 million. Gas costs for the period were $1.9 million (U.S. $1.7 million), as compared to $1.5 million (U.S. $1.5 million) in the same period in 2013. The increase in gas costs is largely due to a an increase in the average cost of natural gas per MMBTU and a stronger U.S. dollar, as compared to the same period in 2013.

As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales' (see non-GAAP Financial Measures) as an appropriate measure of the division's results. For the three months ended December 31, 2014, net energy sales at the Sanger Thermal Facility totalled $2.4 million (U.S. $2.1 million), as compared to $2.4 million (U.S. $2.2 million) during the same period in 2013.

Operating expenses excluding natural gas costs were $1.3 million (U.S. $1.2 million), as compared to $1.2 million (U.S. $1.1 million) in the same period in 2013. The Sanger Thermal Facility's resulting net operating income for the three months ended December 31, 2014 was $1.7 million (U.S. $1.5 million), as compared to $1.8 million (U.S. $1.6 million) during the same period in 2013; the net U.S. dollar impact on the change in the Sanger Thermal Facility's net operating income was nil.

APPENDIX H

LIBERTY UTILITIES
ORGANIZATION CHART
AS OF FEBRUARY 18, 2016

NOTES

1. Unless otherwise indicated, the ownership of all entities is 100%.
2. Defined terms have the meaning ascribed to them in Algonquin Power & Utilities Corp's ("Algonquin") most recent Annual Information Form.
3. "Non-Algonquin" means that the entity in question would not satisfy the definition of an "APCo Entity" in Algonquin's credit agreement.
4. The highlighted boxes denote facilities/assets that are owned by the legal entities, not the legal entity.

KEY

1.	Corporation or LLC	☐ (white box)
2.	Facility or Asset	■ (yellow box)

Chart A

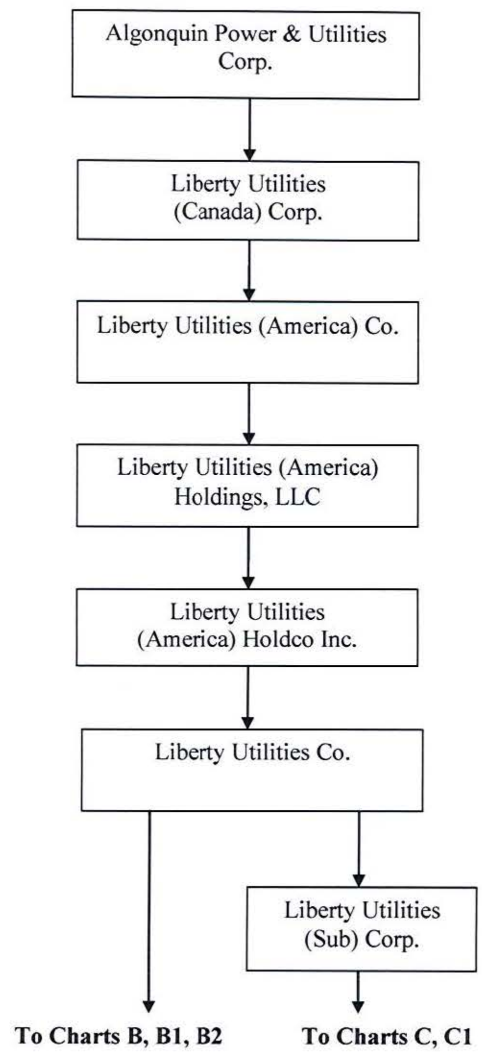

Algonquin Power & Utilities Corp.
Liberty Utilities (Canada) Corp.
Liberty Utilities (America) Co.
Liberty Utilities (America) Holdings, LLC
Liberty Utilities (America) Holdco Inc.
Liberty Utilities Co.
Liberty Utilities (Sub) Corp.
To Charts B, B1, B2
To Charts C, C1

Chart B
(Continued on Chart B1, B2)

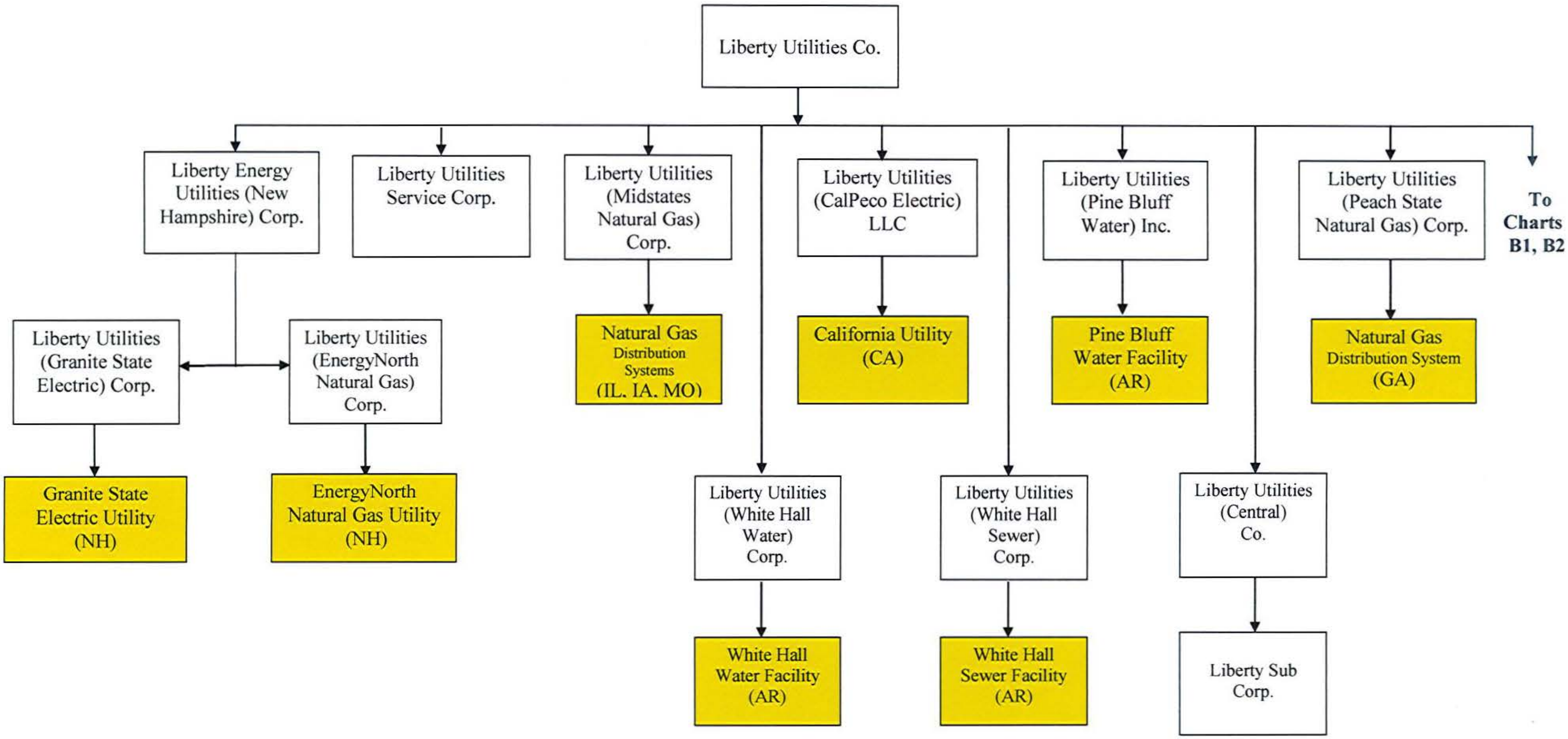


Chart B1

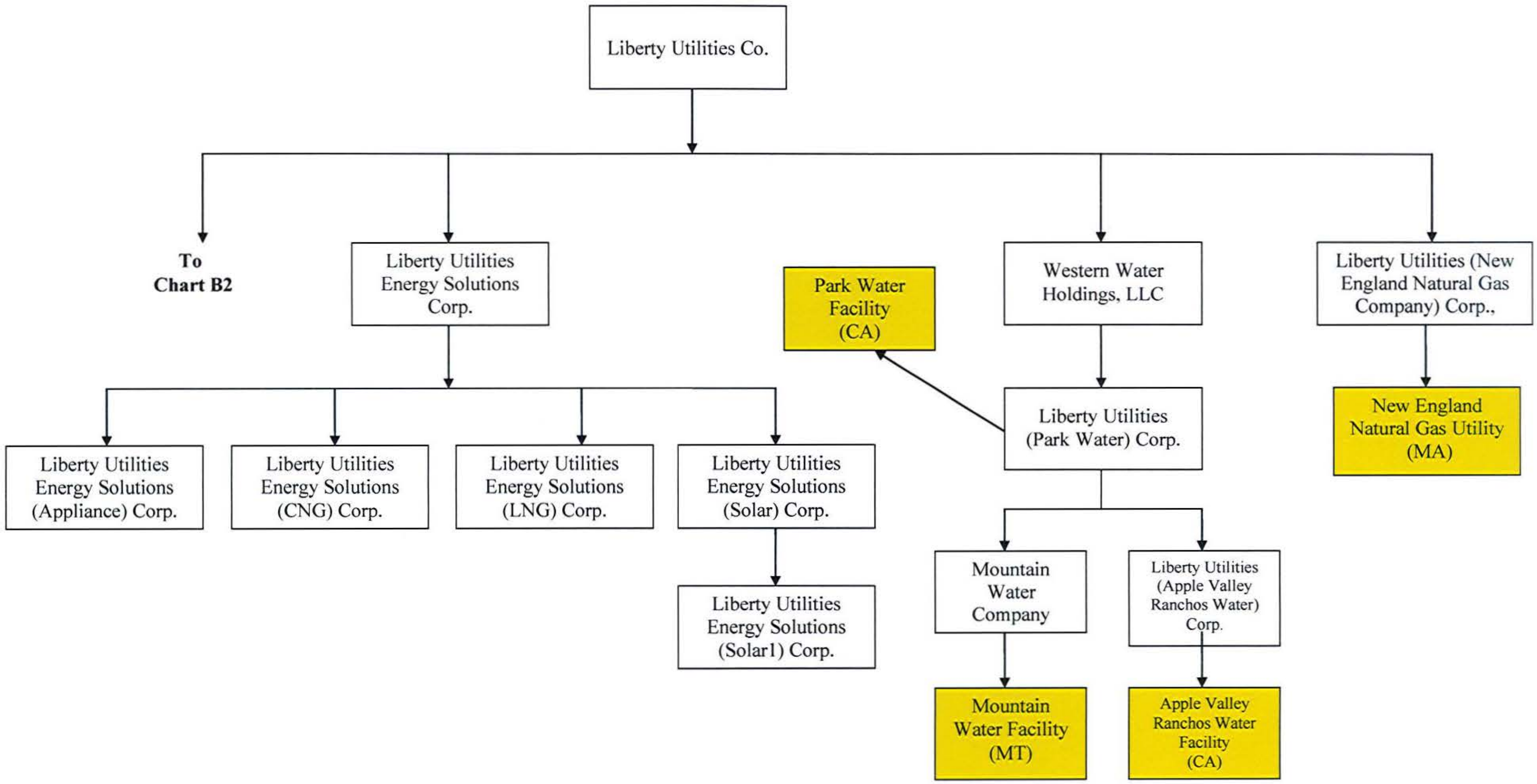

Liberty Utilities Co.
To Chart B2
Liberty Utilities Energy Solutions Corp.
Park Water Facility (CA)
Western Water Holdings, LLC
Liberty Utilities (New England Natural Gas Company) Corp.,
Liberty Utilities (Park Water) Corp.
New England Natural Gas Utility (MA)
Liberty Utilities Energy Solutions (Appliance) Corp.
Liberty Utilities Energy Solutions (CNG) Corp.
Liberty Utilities Energy Solutions (LNG) Corp.
Liberty Utilities Energy Solutions (Solar) Corp.
Mountain Water Company
Liberty Utilities (Apple Valley Ranchos Water) Corp.
Liberty Utilities Energy Solutions (Solar1) Corp.
Mountain Water Facility (MT)
Apple Valley Ranchos Water Facility (CA)

Chart B2

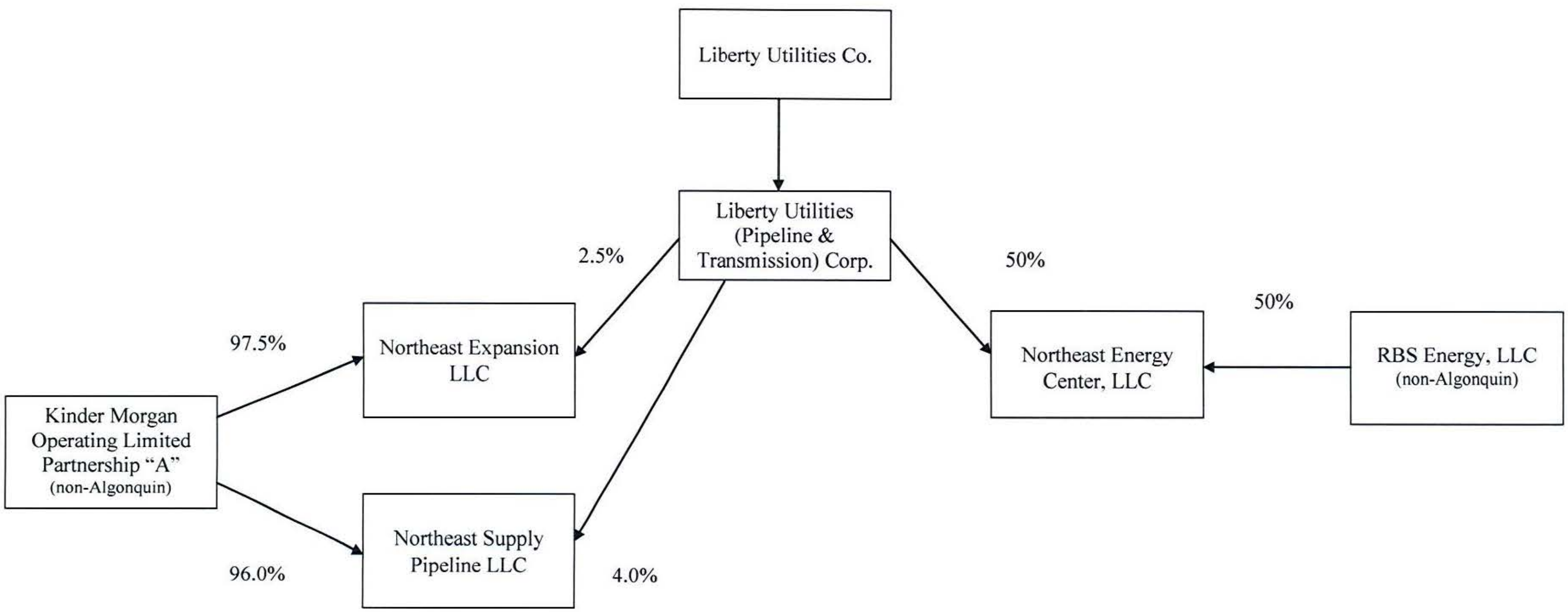

Liberty Utilities Co.
Liberty Utilities (Pipeline & Transmission) Corp.
2.5%
50%
50%
97.5%
Northeast Expansion LLC
Northeast Energy Center, LLC
RBS Energy, LLC (non-Algonquin)
Kinder Morgan Operating Limited Partnership "A" (non-Algonquin)
Northeast Supply Pipeline LLC
96.0%
4.0%

Chart C
(continued on Chart C1)

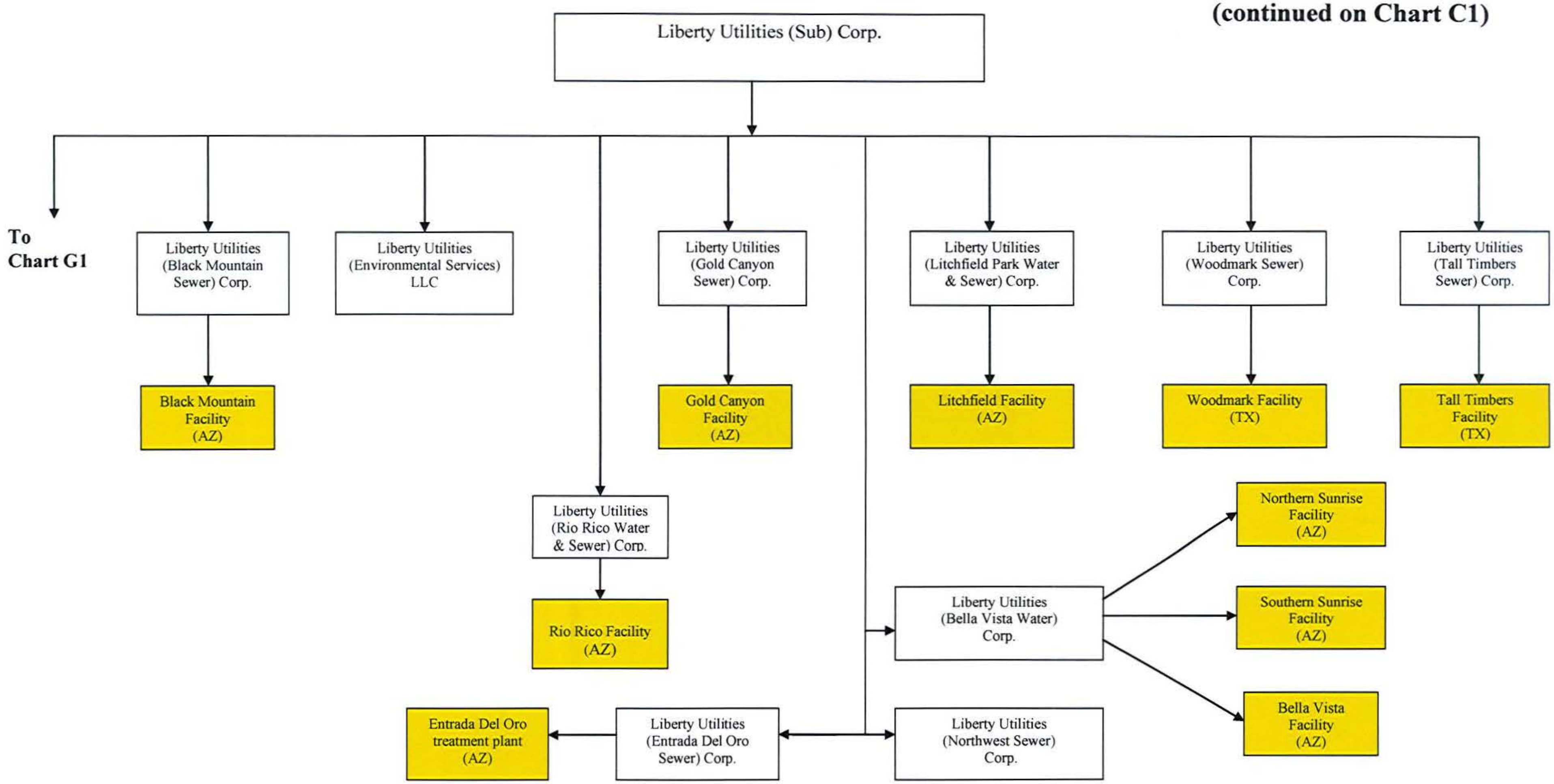
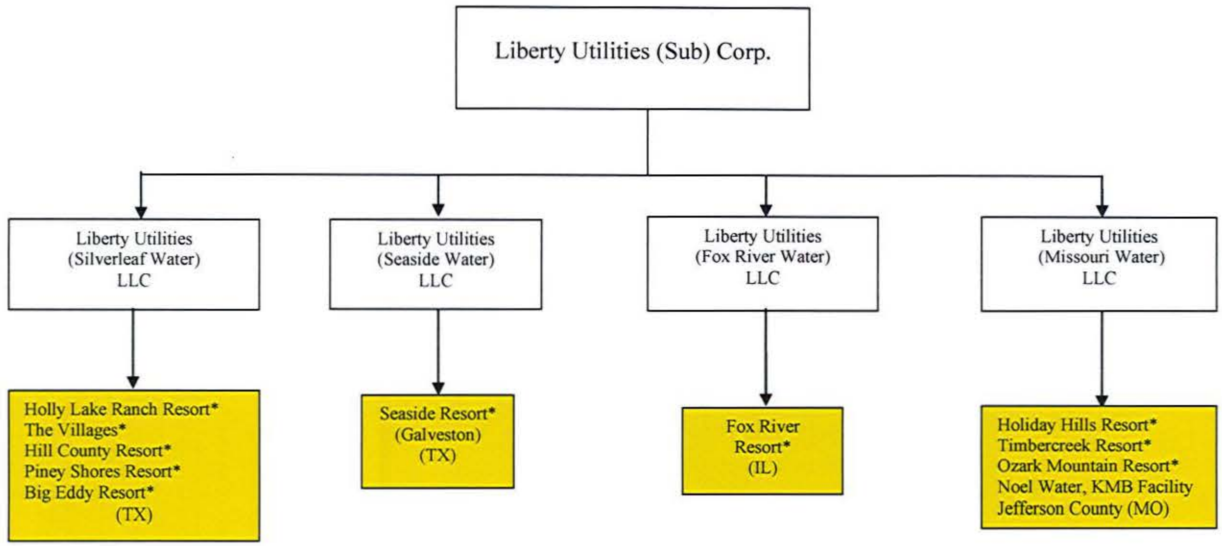


Chart C1



* Algonquin owns water treatment plants, water wells, lines, wastewater collection systems, rest line wastewater treatment plants and certain other assets located at these resorts.

APPENDIX I

AGREEMENT AND PLAN OF MERGER

by and among

THE EMPIRE DISTRICT ELECTRIC COMPANY,

LIBERTY UTILITIES (CENTRAL) CO.

and

LIBERTY SUB CORP.

Dated as of February 9, 2016

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AGREEMENT AND PLAN OF MERGER

This AGREEMENT AND PLAN OF MERGER (this "**Agreement**"), dated as of February 9, 2016, is by and among THE EMPIRE DISTRICT ELECTRIC COMPANY, a Kansas corporation (the "**Company**"), LIBERTY UTILITIES (CENTRAL) CO., a Delaware corporation ("**Parent**"), and LIBERTY SUB CORP., a Kansas corporation ("**Merger Sub**" and, together with the Company and Parent, the "**Parties**").

RECITALS

WHEREAS, the Parties intend that, upon the terms and subject to the conditions set forth herein, at the Effective Time, Merger Sub will merge with and into the Company, with the Company surviving such merger;

WHEREAS, the board of directors of the Company (the "**Company Board**") has (a) determined that it is in the best interests of the Company and its shareholders, and declared it advisable, for the Company to enter into this Agreement, (b) adopted this Agreement and approved the Company's execution, delivery and performance of this Agreement and the consummation of the transactions contemplated by this Agreement and (c) resolved to recommend that the Company's shareholders approve this Agreement;

WHEREAS, the board of directors of Parent has (a) determined that it is in the best interests of Parent and its shareholder, and declared it advisable, for Parent to enter into this Agreement and (b) adopted this Agreement and approved Parent's execution, delivery and performance of this Agreement and the consummation of the transactions contemplated by this Agreement;

WHEREAS, the board of directors of Merger Sub has (a) determined that it is in the best interests of Merger Sub and its shareholder, and declared it advisable, for Merger Sub to enter into this Agreement, (b) adopted this Agreement and approved Merger Sub's execution, delivery and performance of this Agreement and the consummation of the transactions contemplated by this Agreement and (c) resolved to recommend that Merger Sub's sole shareholder, approve this Agreement;

WHEREAS, Parent has approved this Agreement by written consent in its capacity as the sole shareholder of Merger Sub; and

WHEREAS, the Company, Parent and Merger Sub desire to make certain representations, warranties, covenants and agreements specified herein in connection with this Agreement.

NOW, THEREFORE, in consideration of the foregoing and the representations, warranties, covenants and agreements set forth herein, and subject to the conditions set forth herein, and each intending to be legally bound hereby, the Parties agree as follows:

ARTICLE I

THE MERGER

SECTION 1.01 The Merger. At the Effective Time, upon the terms and subject to the conditions set forth herein, Merger Sub shall be merged with and into the Company in accordance with the Kansas General Corporation Code (the "**GCC**") and this Agreement (the "**Merger**"), and the separate corporate existence of Merger Sub shall cease. The Company shall be the surviving corporation in the Merger (sometimes referred to herein as the "**Surviving Corporation**").

SECTION 1.02 The Effective Time. As soon as practicable on the Closing Date, the Company shall deliver to the Office of the Secretary of State of the State of Kansas a certificate of merger with respect to the Merger, in such form as is required by, and executed in accordance with, the relevant provisions of the GCC (the "**Certificate of Merger**"). The Merger shall become effective at the time the Certificate of Merger is duly filed with the Office of the Secretary of State of the State of Kansas in accordance with the GCC or at such later time as is permissible in accordance with the GCC and, as the Parties may mutually agree, as specified in the Certificate of Merger (the time the Merger becomes effective, the "**Effective Time**").

SECTION 1.03 The Closing. Unless this Agreement has been terminated in accordance with Section 8.01, the consummation of the Merger (the "**Closing**") shall take place at the offices of Cahill Gordon & Reindel LLP at 10:00 a.m. New York City time on a date to be mutually agreed to by the Parties, which date shall be no later than the fifteenth Business Day after the satisfaction or waiver of the conditions to the Closing set forth in Article VII (except for those conditions to the Closing that by their terms are to be satisfied at the Closing but subject to the satisfaction or waiver of such conditions) unless another time, date or place is mutually agreed to in writing by the Parties. The date on which the Closing occurs is referred to herein as the "**Closing Date**."

SECTION 1.04 Effects of the Merger. The Merger shall have the effects specified herein and in the applicable provisions of the GCC, including Article 67 thereof.

SECTION 1.05 Organizational Documents. As of the Effective Time, the articles of incorporation of the Surviving Corporation shall be amended and restated to be the same as the articles of incorporation of Merger Sub, as in effect immediately prior to the Effective Time, until thereafter amended as provided therein and in accordance with applicable Law, except that the name of the Surviving Corporation shall be "The Empire District Electric Company". As of the Effective Time, the bylaws of the Surviving Corporation shall be amended and restated to be the same as the bylaws of Merger Sub, as in effect immediately prior to the Effective Time, until thereafter amended as provided therein and in accordance with applicable Law, except that the name of the Surviving Corporation shall be The Empire District Electric Company".

SECTION 1.06 Surviving Corporation Directors and Officers. As of the Effective Time, (i) the directors of Merger Sub as of immediately prior to the Effective Time shall be the directors of the Surviving Corporation and (ii) the officers of the Company as of immediately prior to the Effective Time shall be the officers of the Surviving Corporation, in each case until their successors have been duly elected or appointed or until their earlier death, resignation or removal.

ARTICLE II

EFFECT ON CAPITAL STOCK; EXCHANGE OF CERTIFICATES AND BOOK-ENTRY SHARES

SECTION 2.01 Effect of Merger on Capital Stock.

(a) Cancellation of Treasury Stock and Parent-Owned Stock; Dissenting Stockholders; Conversion of Company Common Stock; Conversion of Merger Sub Common Stock. At the Effective Time, by virtue of the Merger and without any action on the part of the Company, Parent, Merger Sub or any holder of shares of Company Common Stock:

(i) each share of common stock, $1.00 par value, of the Company ("**Company Common Stock**") that is owned by (x) the Company as treasury stock, if any, each share of

Company Common Stock that is owned by a wholly owned Subsidiary of the Company, if any, and each share of Company Common Stock that is owned directly or indirectly by Guarantor or any of its Subsidiaries, if any, immediately prior to the Effective Time and (y) stockholder ("**Dissenting Stockholders**") who have perfected and not withdrawn a demand for appraisal rights pursuant to Section 17-6712 of the GCC (each share of Company Common Stock referred to in clause (x) or clause (y) being an "**Excluded Share**" and collectively, "**Excluded Shares**") shall no longer be outstanding and shall automatically be canceled and retired and shall cease to exist, and no consideration shall be delivered in exchange therefor, subject to any rights the holder thereof may have under Section 2.02(i);

(ii) subject to Section 2.01(b), each share of Company Common Stock issued and outstanding immediately prior to the Effective Time (except for the Excluded Shares) shall be converted automatically into the right to receive an amount in cash (without interest) equal to the Merger Consideration, payable as provided in Section 2.02, and, when so converted, shall automatically be canceled and retired and shall cease to exist;

(iii) each share of common stock, par value $1.00 per share, of Merger Sub issued and outstanding immediately prior to the Effective Time shall be converted into one share of common stock, $1.00 par value, of the Surviving Corporation and shall constitute the only outstanding shares of capital stock of the Surviving Corporation.

(b) Adjustments to Merger Consideration. If at any time during the period between the date of this Agreement and the Effective Time, any change in the outstanding shares of capital stock of the Company (or any other securities convertible therefor or exchangeable thereto) shall occur as a result of any reclassification, stock split (including a reverse stock split), combination, exchange or readjustment of shares, or any stock dividend or stock distribution with a record date during such period, or any similar event, the Merger Consideration and any other similarly dependent items shall be equitably adjusted to provide to Parent, Merger Sub, and the holders of Company Common Stock the same economic effect as contemplated by this Agreement prior to such action.

SECTION 2.02 Payment for Shares.

(a) Paying Agent. Prior to the Effective Time, Parent and the Company shall appoint Wells Fargo Bank, N.A. or such other Person as the Parties may mutual agree to act as paying agent (the "**Paying Agent**") for the purpose of exchanging shares of Company Common Stock for the Merger Consideration in accordance with Section 2.01(a)(ii). At or prior to the Effective Time, Parent shall irrevocably deposit or cause to be deposited with the Paying Agent, in trust for the benefit of the holders of Company Common Stock contemplated by Section 2.01(a)(ii), cash in an amount equal to the aggregate amount of the Merger Consideration pursuant to Section 2.01(a)(ii) (the "**Payment Fund**").

(b) Payment Procedures.

(i) Promptly after the Effective Time (but no later than two (2) Business Days after the Effective Time), the Paying Agent will mail to each holder of record of a certificate representing outstanding shares of Company Common Stock immediately prior to the Effective Time (a "**Certificate**") and to each holder of uncertificated shares of Company Common Stock represented by book entry immediately prior to the Effective Time ("**Book-Entry Shares**"), in each case, whose shares were converted into the right to receive the Merger Consideration pursuant to Section 2.01(a)(ii):

(1) a letter of transmittal, which shall specify that delivery shall be effected, and that risk of loss and title to Certificates or Book-Entry Shares held by such holder will pass, only upon delivery of such Certificates or Book-Entry Shares to the Paying Agent and which shall be in form and substance reasonably satisfactory to Parent and the Company, and

(2) instructions for use in effecting the surrender of such Certificates or Book-Entry Shares in exchange for the Merger Consideration with respect to such shares.

(ii) Upon surrender to, and acceptance in accordance with Section 2.02(b)(iii) by, the Paying Agent of a Certificate or Book-Entry Share, the holder thereof will be entitled to the Merger Consideration payable in respect of the number of shares of Company Common Stock formerly represented by such Certificate or Book-Entry Share surrendered under this Agreement.

(iii) The Paying Agent will accept Certificates or Book-Entry Shares upon compliance with such reasonable terms and conditions as the Paying Agent may impose to effect an orderly exchange of the Certificates and Book-Entry Shares in accordance with customary exchange practices.

(iv) From and after the Effective Time, no further transfers may be made on the records of the Company or its transfer agent of Certificates or Book-Entry Shares, and if any Certificate or Book-Entry Share is presented to the Company for transfer, such Certificate of Book-Entry Share shall be canceled against delivery of the Merger Consideration payable in respect of the shares of Company Common Stock represented by such Certificate or Book-Entry Share.

(v) If any Merger Consideration is to be remitted to a name other than that in which a Certificate or Book-Entry Share is registered, no Merger Consideration may be paid in exchange for such surrendered Certificate or Book-Entry Share unless:

(1) either (A) the Certificate so surrendered is properly endorsed, with signature guaranteed, or otherwise in proper form for transfer or (B) the Book-Entry Share is properly transferred; and

(2) the Person requesting such payment shall (A) pay any transfer or other Taxes required by reason of the payment to a Person other than the registered holder of the Certificate or Book-Entry Share or (B) establish to the satisfaction of the Paying Agent that such Tax has been paid or is not payable.

(vi) At any time after the Effective Time until surrendered as contemplated by this Section 2.02, each Certificate or Book-Entry Share shall be deemed to represent only the right to receive upon such surrender the Merger Consideration payable in respect of the shares of Company Common Stock represented by such Certificate or Book-Entry Share as contemplated by Section 2.01(a)(ii). No interest will be paid or accrued for the benefit of holders of Certificates or Book-Entry Shares on the Merger Consideration payable in respect of the shares of Company Common Stock represented by Certificates or Book-Entry Shares.

(c) No Further Ownership Rights in Company Common Stock.

(i) At the Effective Time, each holder of a Certificate, and each holder of Book-Entry Shares, will cease to have any rights with respect to such shares of Company Common Stock, except, to the extent provided by Section 2.01, for the right to receive the Merger Consideration payable in respect of the shares of Company Common Stock formerly represented by such Certificate or Book-Entry Shares upon surrender of such Certificate or Book-Entry Share in accordance with Section 2.02(b);

(ii) The Merger Consideration paid upon the surrender or exchange of Certificates or Book-Entry Shares in accordance with this Section 2.02 will be deemed to have been paid in full satisfaction of all rights pertaining to the shares of Company Common Stock formerly represented by such Certificates or Book-Entry Shares.

(d) Termination of Payment Fund. The Paying Agent will deliver to the Surviving Corporation, upon the Surviving Corporation's demand, any portion of the Payment Fund (including any interest and other income received by the Paying Agent in respect of all such funds) which remains undistributed to the former holders of Certificates or Book-Entry Shares upon expiration of the period ending one (1) year after the Effective Time. Thereafter, any former holder of Certificates or Book-Entry Shares prior to the Merger who has not complied with this Section 2.02 prior to such time, may look only to the Surviving Corporation for payment of his, her or its claim for Merger Consideration to which such holder may be entitled.

(e) Investment of Payment Fund. The Paying Agent shall invest any cash in the Payment Fund if and as directed by Parent; provided that such investment shall be in obligations of, or guaranteed by, the United States of America, in commercial paper obligations of issuers organized under the Law of a state of the United States of America, rated A-1 or P-1 or better by Moody's Investors Service, Inc. or Standard & Poor's Ratings Service, respectively, or in certificates of deposit, bank repurchase agreements or bankers' acceptances of commercial banks with capital exceeding $10,000,000,000, or in mutual funds investing in such assets. Any interest and other income resulting from such investments shall be paid to, and be the property of, Parent. No investment losses resulting from investment of the Payment Fund shall diminish the rights of any of the Company's shareholders to receive the Merger Consideration or any other payment as provided herein. To the extent there are losses with respect to such investments or the Payment Fund diminishes for any other reason below the level required to make prompt cash payment of the aggregate funds required to be paid pursuant to the terms hereof, Parent shall reasonably promptly replace or restore the cash in the Payment Fund so as to ensure that the Payment Fund is at all times maintained at a level sufficient to make such cash payments.

(f) No Liability. None of the Company, Parent, Merger Sub, the Surviving Corporation or the Paying Agent shall be liable to any Person in respect of any portion of the Payment Fund delivered to a public official pursuant to any applicable abandoned property, escheat or similar Law.

(g) Withholding Taxes. Each of Parent, the Surviving Corporation and the Paying Agent shall be entitled to deduct and withhold from the consideration otherwise payable pursuant to this Agreement to any holder of Certificates, Book-Entry Shares, Time-Vested Restricted Stock Awards or Performance-Based Restricted Stock Awards such amounts as may be required to be deducted and withheld with respect to the making of such payment under applicable Tax Law. Amounts so withheld and paid over to the appropriate taxing authority shall be treated for all purposes under this Agreement as having been paid to the holder of Certificates, Book-Entry Shares, Time-Vested Restricted Stock Awards or Performance-Based Restricted Stock Awards, as applicable, in respect of which such deduction or withholding was made.

(h) Lost, Stolen or Destroyed Certificates. If any Certificate formerly representing shares of Company Common Stock has been lost, stolen or destroyed, upon the making of an affidavit of that fact by the Person claiming such Certificate to be lost, stolen or destroyed and, if required by Parent, the posting by such Person of a bond, in such reasonable and customary amount as Parent may direct, as indemnity against any claim that may be made against it with respect to such Certificate, the Paying Agent shall deliver and pay, in exchange for such lost, stolen or destroyed certificate, the Merger Consideration payable in respect thereof pursuant to this Agreement.

(i) Appraisal Rights. No Person who has perfected a demand for appraisal rights pursuant to Section 17-6712 of the GCC shall be entitled to receive the Merger Consideration with respect to the shares of Company Common Stock owned by such Person unless and until such Person shall have effectively withdrawn or lost such Person's right to appraisal under the GCC. Each Dissenting Stockholder shall be entitled to receive only the payment provided by Section 17-6712 of the GCC with respect to shares of Company Common Stock owned by such Dissenting Stockholder. The Company shall give Parent (i) prompt notice of any demands for appraisal, threatened demands for appraisal, attempted withdrawals of such demands, and any other instruments that are received by the Company relating to stockholders' rights of appraisal (any of the foregoing, a "**Demand**") and (ii) the opportunity to participate in and control all negotiations and proceedings with respect to any Demand. The Company shall not, except with the prior written consent of Parent, voluntarily make any payment with respect to any Demand, offer to settle or settle any such Demand.

SECTION 2.03 Equity Awards.

(a) Each Time-Vested Restricted Stock Award that is outstanding immediately prior to the Effective Time shall be cancelled and converted, as of the Effective Time, into the right to receive a lump-sum cash payment equal to the product of (i) the Merger Consideration, without interest, multiplied by (ii) the product of (1) the total number of shares of Company Common Stock underlying such Time-Vested Restricted Stock Award, multiplied by (2) the ratio equal to (x) the number of months through the Closing Date (rounding a fraction of a month to the next higher number of whole months) in the restricted period under such Time-Vested Restricted Stock Award, divided by (y) the total number of months in the restricted period under such Time-Vested Restricted Stock Award (the "**Time-Vested Restricted Stock Consideration**"). All payments of Time-Vested Restricted Stock Consideration shall be made by the Surviving Corporation, less applicable Tax withholdings, as promptly as practicable following the Effective Time (and in all events no later than the later of (A) five (5) Business Days following the Closing Date and (B) the last day of the Surviving Corporation's first regular payroll cycle following the Closing Date).

(b) Each Performance-Based Restricted Stock Award that is outstanding immediately prior to the Effective Time shall be cancelled and converted, as of the Effective Time, into the right to receive a lump-sum cash payment equal to the product of (i) the Merger Consideration, without interest, multiplied by (ii) the total number of shares of Company Common Stock that would be earned for performance at target over the performance period under such Performance-Based Restricted Stock Award (the "**Performance-Based Restricted Stock Consideration**"). All payments of Performance-Based Restricted Stock Consideration shall be made by the Surviving Corporation, less applicable Tax withholdings, as promptly as practicable following the Effective Time (and in all events no later than the later of (i) five (5) Business Days following the Closing Date and (ii) the last day of the Surviving Corporation's first regular payroll cycle following the Closing).

(c) Each Director Stock Unit that is outstanding immediately prior to the Effective Time shall be cancelled and converted, as of the Effective Time, into the right to receive an amount in cash equal to the Merger Consideration, payment of which amount shall be made by the Surviving Corporation at the time elected or provided pursuant to the terms and conditions of such Director Stock Unit, together with interest on the amount of such payment at the "U.S. Prime Rate" as quoted by the Wall Street Journal in effect at the Effective Time for the period, if any, from the Effective Time until the date of payment of such amount.

(d) Immediately prior to the Effective Time, the Employee Stock Purchase Plan and the right of any employee to continue participation in the Employee Stock Purchase Plan and any purchase period under the Employee Stock Purchase Plan then in effect shall terminate. Payment of all remaining, unused amounts credited to each participant's account under the Employee Stock Purchase Plan, together with interest as provided in the Employee Stock Purchase Plan, shall be made by the Surviving Corporation to the applicable participant as promptly as practicable following the Effective Time.

(e) Prior to the Effective Time, the Company Board or the appropriate committee thereof shall adopt resolutions providing for, and shall take any other actions that are necessary to effect, the treatment of the Time-Vested Restricted Stock Awards, the Performance-Based Restricted Stock Awards, the Director Share Units and the Employee Stock Purchase Plan as contemplated by this Section 2.03, including but not limited to obtaining participant consents (if necessary) with respect to outstanding Time-Vested Restricted Stock Awards, Performance-Based Restricted Stock Awards, and Director Share Units; provided, however, that notwithstanding any other provision hereof, in the event any participant consent is required but not obtained prior to the Effective Time with respect any outstanding award, such award shall be paid in cash in accordance with the applicable Company Benefit Plan.

ARTICLE III

REPRESENTATIONS AND WARRANTIES OF THE COMPANY

Except (a) as set forth in the Company Reports publicly available and filed with or furnished to the SEC prior to the date of this Agreement (excluding any statements that are predictive, cautionary or forward-looking in nature) or (b) subject to Section 9.04(j), as set forth in the corresponding section of the disclosure letter delivered by the Company to Parent concurrently with the execution and delivery by the Company of this Agreement (the "**Company Disclosure Letter**"), the Company represents and warrants to Parent and Merger Sub as follows:

SECTION 3.01 Organization, Standing and Power. Each of the Company and the Company's Subsidiaries (the "**Company Subsidiaries**") is duly organized, validly existing and in active status or good standing, as applicable, under the laws of the jurisdiction in which it is organized (in the case of active status or good standing, to the extent such jurisdiction recognizes such concept), except, in the case of the Company Subsidiaries, where the failure to be so organized, existing or in active status or good standing, as applicable, has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. Each of the Company and the Company Subsidiaries has all requisite entity power and authority to enable it to own, operate, lease or otherwise hold its properties and assets and to conduct its businesses as presently conducted, except where the failure to have such power or authority would not have or would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. Each of the Company and the Company Subsidiaries is duly qualified or licensed to do business in each jurisdiction where the nature of its business or the ownership, operation or leasing of its properties make such qualification necessary, except in any such jurisdiction where the failure to be so qualified or licensed would not have or would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. The Company has made available to Parent true and complete copies of the restated articles of incorporation of the Company in effect as of the date of this Agreement (the "**Company Articles**") and the bylaws of the Company in effect as of the date of this Agreement (the "**Company Bylaws**").

SECTION 3.02 Company Subsidiaries. All the outstanding shares of capital stock or voting securities of, or other equity interests in, each Company Subsidiary have been validly issued and are fully paid and nonassessable and are owned by the Company, by another Company Subsidiary or by the Company and another Company Subsidiary, free and clear of (a) all pledges, liens, charges, mortgages, encumbrances and security interests of any kind or nature whatsoever (collectively, "**Liens**") and (b) any other restriction (including any restriction on the right to vote, sell or otherwise dispose of such capital stock, voting securities or other equity interests), except, in the case of the foregoing clauses (a) and (b), as imposed by this Agreement, the Organizational Documents of the Company Subsidiaries or applicable securities Laws. Section 3.02 of the Company Disclosure Letter sets forth, as of the date of this Agreement, a true and complete list of the Company Subsidiaries. The Company has made available to Parent true and complete copies of the articles of incorporation and bylaws (or equivalent Organizational Documents) of each Company Subsidiary in effect as of the date of this Agreement. Neither the Company nor any Company Subsidiary owns any shares of capital stock or voting securities of, or other equity interests in, any Person other than the Company Subsidiaries.

SECTION 3.03 Capital Structure.

(a) The authorized capital stock of the Company consists of (i) 100,000,000 shares of Company Common Stock, (ii) 2,500,000 shares of preference stock, including 500,000 shares of Series A Participating Preference Stock ("**Preference Stock**") and (iii) 5,000,000 shares of $10.00 par value cumulative preferred stock ("**Preferred Stock**"). At the close of business on February 8, 2016, (x) 43,763,120 shares of Company Common Stock were issued and outstanding, (y) no shares of Company Common Stock were held by the Company in its treasury and (z) no shares of Preference Stock or Preferred Stock were issued and outstanding. At the close of business on February 8, 2016, an aggregate of 1,082,414 shares of Company Common Stock were reserved and available for issuance pursuant to the Company Benefit Plans. At the close of business on February 8, 2016, an aggregate of 125,284 shares of Company Common Stock were issuable on the vesting of outstanding Time-Vested Restricted Stock Awards and Performance-Based Restricted Stock Awards (assuming full satisfaction of the applicable service conditions and maximum attainment of the applicable performance goals).

(b) All outstanding shares of Company Common Stock are validly issued, fully paid and nonassessable and not subject to, or issued in violation of, any preemptive right. Except as set forth in this Section 3.03 or Section 3.03(b) of the Company Disclosure Letter or pursuant to the terms of this Agreement, there are not issued, reserved for issuance or outstanding, and there are not any outstanding obligations of the Company or any Company Subsidiary to issue, deliver or sell, or cause to be issued, delivered or sold, (i) any capital stock of the Company or any Company Subsidiary or any securities of the Company or any Company Subsidiary convertible into or exchangeable or exercisable for shares of capital stock or voting securities of, or other equity interests in, the Company or any Company Subsidiary or (ii) any warrants, calls, options or other rights to acquire from the Company or any Company Subsidiary, or any other obligation of the Company or any Company Subsidiary to issue, deliver or sell, or cause to be issued, delivered or sold, any capital stock or voting securities of, or other equity interests in, the Company or any Company Subsidiary (the foregoing clauses (i) and (ii), collectively, "**Equity Securities**"). Except pursuant to the Company Benefit Plans, there are not any outstanding obligations of the Company or any Company Subsidiary to repurchase, redeem or otherwise acquire any Equity Securities. There is no outstanding Indebtedness of the Company having the right to vote (or convertible into, or exchangeable for, securities having the right to vote) on any matters on which shareholders of the Company may vote ("**Company Voting Debt**"). No Company Subsidiary owns any shares of Company Common Stock.

SECTION 3.04 Authority; Execution and Delivery; Enforceability. The Company has all requisite corporate power and authority to execute and deliver this Agreement, to perform its covenants and agreements hereunder and to consummate the Merger, subject, in the case of the Merger, to the receipt of the Company Shareholder Approval. The Company Board has adopted resolutions, at a meeting duly called at which a quorum of directors of the Company was present, (a) determining that it is in the best interests of the Company and its shareholders, and declaring it advisable, for the Company to enter into this Agreement, (b) adopting this Agreement and approving the Company's execution, delivery and performance of this Agreement and the consummation of the transactions contemplated thereby and (c) resolving to recommend that the Company's shareholders approve this Agreement (the "**Company Board Recommendation**") and directing that this Agreement be submitted to the Company's shareholders for approval at a duly held meeting of such shareholders for such purpose (the "**Company Shareholders Meeting**"). Such resolutions have not been amended or withdrawn as of the date of this Agreement. Except for (i) the approval of this Agreement by the affirmative vote of the holders of a majority of all of the outstanding shares of Company Common Stock entitled to vote at the Company Shareholders Meeting (the "**Company Shareholder Approval**") and (ii) the filing of the Certificate of Merger as required by the GCC, no other vote or corporate proceedings on the part of the Company or its shareholders are necessary to authorize, adopt or approve this Agreement or to consummate the Merger. The Company has duly executed and delivered this Agreement and, assuming the due authorization, execution and delivery by Parent and Merger Sub, this Agreement constitutes its legal, valid and binding obligation, enforceable against it in accordance with its terms, subject in all respects to the effects of bankruptcy, insolvency, fraudulent conveyance, reorganization, moratorium and other Laws relating to or affecting creditors' rights generally and general equitable principles (whether considered in a proceeding in equity or at law) (the "**Bankruptcy and Equity Exceptions**").

SECTION 3.05 No Conflicts; Consents.

(a) The execution and delivery by the Company of this Agreement does not, and the performance by the Company of its covenants and agreements hereunder and the consummation of the Merger will not, (i) subject to obtaining the Company Shareholder Approval, conflict with, or result in any violation of any provision of, the Company Articles, the Company Bylaws or the Organizational Documents of any Company Subsidiary, (ii) subject to obtaining the Consents set forth in Section 3.05(a)(ii) of the Company Disclosure Letter (the "**Company Required Consents**"), conflict with, result in any violation of, or default (with or without notice or lapse of time, or both) under, or give rise to a right of termination, cancellation or acceleration of any material obligation or to the loss of a material benefit under any Filed Company Contract or any material Permit applicable to the business of the Company and the Company Subsidiaries or (iii) subject to obtaining the Company Shareholder Approval and the Consents referred to in Section 3.05(b) and making the Filings referred to in Section 3.05(b), conflict with, or result in any violation of any provision of, any Judgment or Law, in each case, applicable to the Company or any Company Subsidiary or their respective properties or assets, except for, in the case of the foregoing clauses (ii) and (iii), any matter that would not have or would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect and would not prevent or materially impede, interfere with or delay the consummation of the Merger.

(b) No consent, waiver or Permit ("**Consent**") of or from, or registration, declaration, notice or filing ("**Filing**") made to or with, any Governmental Entity is required to be obtained or made by the Company or any Company Subsidiary in connection with the Company's execution and delivery of this Agreement or its performance of its covenants and agreements hereunder or the consummation of the Merger, except for the following:

(i) (1) the filing with the Securities and Exchange Commission (the "**SEC**"), in preliminary and definitive form, of the Proxy Statement and (2) the filing with the SEC of such reports under, and such other compliance with, the Securities Exchange Act of 1934, as amended (the "**Exchange Act**"), or the Securities Act of 1933, as amended (the "**Securities Act**"), and rules and regulations of the SEC promulgated thereunder, as may be required in connection with this Agreement or the Merger;

(ii) compliance with, Filings under and the expiration of any applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, and the rules and regulations promulgated thereunder (the "**HSR Act**");

(iii) the filing of the Certificate of Merger with the Office of the Secretary of State of the State of Kansas and appropriate documents with the relevant authorities of the other jurisdictions in which Parent and the Company are qualified to do business;

(iv) (1) Filings with, and the Consent of, the Federal Energy Regulatory Commission (the "**FERC**") under Section 203 of the Federal Power Act (the "**FPA**"); (2) the CFIUS Approval, and Filings with respect thereto, (3) the Filings with, and the Consent of, the State Commissions, (4) pre-approvals of license transfers with the Federal Communications Commission (the "**FCC**") and (5) and the other Filings and Consents set forth in Section 3.05(b)(iv) of the Company Disclosure Letter (the Consents and Filings set forth in Section 3.05(b)(ii) and this Section 3.05(b)(iv), collectively, the "**Company Required Statutory Approvals**");

(v) the Company Required Consents;

(vi) Filings and Consents as are required to be made or obtained under state or federal property transfer Laws or Environmental Laws; and

(vii) such other Filings or Consents the failure of which to make or obtain would not have or would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect and would not prevent or materially impede, interfere with or delay the consummation of the Merger.

SECTION 3.06 Company Reports; Financial Statements.

(a) The Company has furnished or filed all reports, schedules, forms, statements and other documents (including exhibits and other information incorporated therein) required to be furnished or filed by the Company with the SEC since January 1, 2015 (such documents, together will all exhibits, financial statements, including the Company Financial Statements, and schedules thereto and all information incorporated therein by reference, but excluding the Proxy Statement, being collectively referred to as the "**Company Reports**"). Each Company Report (i) at the time furnished or filed, complied in all material respects with the applicable requirements of the Exchange Act, the Securities Act or the Sarbanes-Oxley Act of 2002 (including the rules and regulations promulgated thereunder), as the case may be, and the rules and regulations of the SEC promulgated thereunder applicable to such Company Report and (ii) did not at the time it was filed (or if amended or superseded by a filing or amendment prior to the date of this Agreement, then at the time of such filing or amendment) contain any untrue statement of a material fact or omit to state a material fact required to be stated therein or necessary in order to make the statements therein, in the light of the circumstances under which they were made, not misleading. Each of the consolidated financial statements of the Company included in the Company Reports (the "**Company Financial Statements**") complied at the time it was filed as to form in all material respects with applicable accounting requirements and the published rules and regulations of the SEC with respect thereto, was prepared in accordance with United States generally accepted accounting principles ("**GAAP**") (except, in the case of unaudited quarterly financial statements, as permitted by Form 10-Q of the SEC) applied on a consistent basis during the periods and as of the dates involved (except as may be indicated in the notes thereto) and fairly present in all material respects, in accordance with GAAP, the consolidated financial position of the Company and the Company's consolidated Subsidiaries as of the dates thereof and the consolidated results of their operations and cash flows for the periods shown (subject, in the case of unaudited quarterly financial statements, to normal year-end audit adjustments).

(b) Neither the Company nor any Company Subsidiary has any liability of any nature that is required by GAAP to be set forth on a consolidated balance sheet of the Company and the Company Subsidiaries, except liabilities (i) reflected or reserved against in the most recent balance sheet (including the notes thereto) of the Company and the Company Subsidiaries included in the Company Reports filed prior to the date hereof, (ii) incurred in the ordinary course of business after September 30, 2015 (the "**Balance Sheet Date**"), (iii) incurred in connection with the Merger or any other transaction or agreement contemplated by this Agreement or (iv) that have not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

(c) The Company maintains a system of "internal control over financial reporting" (as defined in Rule 13a-15 or 15d-15, as applicable, under the Exchange Act). Such internal control over financial reporting is effective in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP in all material respects. Except as has not had, and would not be reasonably likely to have, individually or in the aggregate, a Company Material Adverse Effect, (i) the Company maintains "disclosure controls and procedures" required by Rule 13a-15 or 15d-15 under the Exchange Act that are effective to ensure that information required to be disclosed by the Company in the reports it files or submits under the Exchange Act is recorded, processed, summarized and reported on a timely basis to the individuals responsible for the preparation of the Company's filings with the SEC and other public disclosure documents and (ii) the Company has disclosed, based on its most recent evaluation prior to the date of this Agreement, to the Company's outside auditors and the audit committee of the Company Board (1) any significant deficiencies and material weaknesses in the design or operation of internal controls over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that are reasonably likely to adversely affect the Company's ability to record, process, summarize and report financial information and (2) any fraud, known to the Company, whether or not material, that involves management or other employees who have a significant role in the Company's internal controls over financial reporting.

SECTION 3.07 Absence of Certain Changes or Events. From the Balance Sheet Date to the date of this Agreement, each of the Company and the Company Subsidiaries has conducted its respective business in the ordinary course of business in all material respects, and during such period there has not occurred any fact, circumstance, effect, change, event or development that has had or would reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

SECTION 3.08 Taxes.

(a) Except as would not have or would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect:

(i) (1) each of the Company and each Company Subsidiary has timely filed, taking into account any extensions, all Tax Returns required to have been filed and such Tax Returns are accurate and complete in all respects and (2) all Taxes due on such Tax Returns have been timely paid in full;

(ii) (1) neither the Company nor any Company Subsidiary has received written notice of any audit, examination, investigation or other proceeding from any taxing authority for any amount of unpaid Taxes asserted against the Company or any Company Subsidiary that have not been fully paid or settled and (2) with respect to any tax years open for audit as of the date hereof, neither the Company nor any Company Subsidiary has granted any waiver of any statute of limitations with respect to, or any extension of a period for the assessment of, any Tax;

(iii) neither the Company nor any Company Subsidiary had any liabilities for unpaid Taxes as of the date of the latest balance sheet included in the Company Financial Statements that had not been accrued or reserved on such balance sheet in accordance with GAAP and (2) neither the Company nor any Company Subsidiary has incurred any liability for Taxes since the date of the latest balance sheet included in the Company Financial Statements except in the ordinary course of business;

(iv) neither the Company nor any Company Subsidiary has any liability for Taxes of any Person (except for the Company or any Company Subsidiary) arising from the application of Treasury Regulation Section 1.1502-6 or any analogous provision of state, local or foreign Law, or as a transferee or successor, by contract or otherwise;

(v) neither the Company nor any Company Subsidiary is a party to or is otherwise bound by any Tax sharing, allocation or indemnification agreement or arrangement, except for such an agreement or arrangement (1) exclusively between or among the Company and Company Subsidiaries, or (2) with customers, vendors, lessors or other third parties entered into in the ordinary course of business and not primarily related to Taxes;

(vi) within the past three (3) years, neither the Company nor any Company Subsidiary has been a "distributing corporation" or a "controlled corporation" in a distribution intended to qualify for tax-free treatment under Section 355 of the Code;

(vii) neither the Company nor any Company Subsidiary has engaged in any "listed transaction" as defined in Treasury Regulations Section 1.6011-4(b)(2) or Treasury Regulations Section 301.6111-2(b) in any tax year for which the statute of limitations has not expired;

(viii) Neither the Company nor any Company Subsidiary will be required, for income Tax purposes for any taxable period ending after the Closing Date, to include in its taxable income any item of income or gain or to exclude from its taxable income any item of deduction or loss as a result of any (i) change in method of accounting under Section 481(c) of the Code (or any corresponding or similar provision of state, local or foreign law) for a taxable period ending on or prior to the Closing Date, (ii) closing agreement under Section 7121 of the Code (or any corresponding or similar provision of state, local or foreign law) executed on or prior to the Closing Date, (iii) installment sale or open transaction disposition occurring on or prior to the Closing Date or (iv) prepaid amount received on or prior to the Closing Date; and

(ix) No written claim has been received in the last three years by the Company or any Company Subsidiary from a taxing authority in a jurisdiction where the Company or Company Subsidiary does not file Tax Returns that the Company or Company Subsidiary is or may be subject to taxation by that jurisdiction or should have been included in a combined, consolidated, affiliated, unitary or other group Tax Return of that jurisdiction.

(b) Except to the extent Section 3.09 relates to Taxes, the representations and warranties contained in this Section 3.08 are the sole and exclusive representations and warranties of the Company relating to Taxes, and no other representation or warranty of the Company contained herein shall be construed to relate to Taxes.

SECTION 3.09 Employee Benefits.

(a) Section 3.09(a) of the Company Disclosure Letter sets forth a complete and accurate list, as of the date of this Agreement, of each material Company Benefit Plan and each material Company Benefit Agreement.

(b) With respect to each material Company Benefit Plan and material Company Benefit Agreement, the Company has made available to Parent, to the extent applicable, complete and accurate copies of (i) the plan document (or, if such arrangement is not in writing, a written description of the material terms thereof), including any amendment thereto and any summary plan description thereof, (ii) each trust, insurance, annuity or other funding Contract related thereto, (iii) the most recent audited financial statement and actuarial or other valuation report prepared with respect thereto, (iv) the most recent annual report on Form 5500 required to be filed with the Internal Revenue Service (the "**IRS**") with respect thereto and (v) the most recently received IRS determination letter or opinion. No Company Benefit Plan or Company Benefit Agreement is maintained outside the jurisdiction of the United States, or covers any Company Personnel residing or working outside of the United States.

(c) Except as, individually or in the aggregate, has not had and would not reasonably be expected to have a Company Material Adverse Effect, (i) each Company Benefit Plan and each Company Benefit Agreement has been maintained in compliance with its terms and with the requirements prescribed by ERISA, the Code and all other applicable Laws, (ii) there are no pending or, to the Knowledge of the Company, threatened proceedings against any Company Benefit Plan or Company Benefit Agreement or any fiduciary thereof, or the Company or any Company Subsidiary with respect to any Company Benefit Plan or Company Benefit Agreement and (iii) all contributions, reimbursements, premium payments and other payments required to be made by the Company or any Company Commonly Controlled Entity to any Company Benefit Plan have been made on or before their applicable due dates. Except as, individually or in the aggregate, has not had and would not reasonably be expected to have a Company Material Adverse Effect, neither the Company nor any Company Commonly Controlled Entity has engaged in, and to the Knowledge of the Company, there has not been, any non-exempt transaction prohibited by ERISA or by Section 4975 of the Code with respect to any Company Benefit Plan or Company Benefit Agreement or their related trusts that would reasonably be expected to result in a liability of the Company or a Company Commonly Controlled Entity. Except as has not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, no Company Benefit Plan or Company Benefit Agreement is under audit or is the subject of an administrative proceeding by the IRS, the Department of Labor, or any other Governmental Entity, nor has the Company received written notice of the commencement of any such audit or other administrative proceeding.

(d) Section 3.09(d) of the Company Disclosure Letter sets forth each Company Benefit Plan and Company Benefit Agreement that is subject to Section 302 or Title IV of ERISA or Section 412, 430 or 4971 of the Code. No Company Benefit Plan or Company Benefit Agreement is a multiemployer plan, as defined in Section 3(37) of ERISA, or a plan that has two or more contributing sponsors at least two of whom are not under common control, within the meaning of Section 4063 of ERISA, and neither the Company nor any Company Commonly Controlled Entity has contributed to or been obligated to contribute to any such plan within the six years preceding this Agreement. Except for matters that have not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, neither the Company nor any Company Commonly Controlled Entity has incurred any Controlled Group Liability (as defined below) that has not been satisfied in full nor do any circumstances exist that could reasonably be expected to give rise to any Controlled Group Liability (except for the payment of premiums to the Pension Benefit Guaranty Corporation). For the purposes of this Agreement, "**Controlled Group Liability**" means any and all liabilities (i) under Title IV of ERISA, (ii) under Section 302 of ERISA, (iii) under Sections 412, 430 and 4971 of the Code or (iv) as a result of a failure to comply with the continuation coverage requirements of Section 601 et seq. of ERISA and Section 4980B of the Code.

(e) Each Company Benefit Plan that is intended to be qualified under Section 401(a) of the Code is so qualified and such plan has received a currently effective favorable determination letter or opinion to that effect from the IRS and, to the Knowledge of the Company, there is no reason why any such determination letter should be revoked or not be reissued.

(f) Except for any liabilities that have not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, neither the Company nor any Company Subsidiary has any liability for providing health, medical or other welfare benefits after retirement or other termination of employment, except for coverage or benefits required to be provided under Section 4980(B)(f) of the Code or applicable Law.

(g) Except as expressly provided in this Agreement or as set forth in Section 3.09(g) of the Company Disclosure Letter, none of the execution and delivery of this Agreement, the performance by either party of its covenants and agreements hereunder or the consummation of the Merger (alone or in conjunction with any other event, including any termination of employment on or following the Effective Time) will (i) entitle any Company Personnel to any material compensation or benefit, (ii) accelerate the time of payment or vesting, or trigger any payment or funding, of any material compensation or benefit or trigger any other material obligation under any Company Benefit Plan or Company Benefit Agreement or (iii) result in any payment that could, individually or in combination with any other such payment, not be deductible under Section 280G of the Code.

(h) The representations and warranties contained in this Section 3.09 are the sole and exclusive representations and warranties of the Company relating to Company Benefit Plans or Company Benefit Agreements (including their compliance with any applicable Law) or ERISA, and no other representation or warranty of the Company contained herein shall be construed to relate to Company Benefit Plans or Company Benefit Agreements (including their compliance with any applicable Law) or ERISA.

SECTION 3.10 Labor and Employment Matters. Except as set forth in Section 3.10 of the Company Disclosure Letter, neither the Company nor any Company Subsidiary is party to any collective bargaining agreement or similar labor union Contract with respect to any of their respective employees (the Contracts set forth in Section 3.10 of the Company Disclosure Letter, the "**Company Union Contracts**"). To the Knowledge of the Company, no employees of the Company or any Company Subsidiary are represented by any other labor union with respect to their employment for the Company or any Company Subsidiary. To the Knowledge of the Company, except as would not have or would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, (a) there are no labor union representation or certification proceedings with respect to employees of the Company or any Company Subsidiary pending or threatened in writing to be brought or filed with the National Labor Relations Board, and (b) there are no labor union organizing activities, with respect to employees of the Company or any Company Subsidiary. From the Balance Sheet Date until the date of this Agreement, except as would not have or would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, there have been no labor union strikes, slowdowns, work stoppages or lockouts or other material labor disputes pending or threatened in writing against or affecting the Company or any Company Subsidiary.

SECTION 3.11 Litigation. There is no Claim before any Governmental Entity pending or, to the Knowledge of the Company, threatened against the Company or any Company Subsidiary that has had or would reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. There is no Judgment outstanding against or, to the Knowledge of the Company, investigation by any Governmental Entity of the Company or any Company Subsidiary or any of their respective properties or assets that has had or would reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect. This Section 3.11 does not relate to Taxes; Company Benefit Plans or Company Benefit Agreements (including their compliance with any applicable Law) or ERISA; or environmental matters; or Intellectual Property, which are addressed in Sections 3.08, 3.09, 3.14 and 3.17, respectively.

SECTION 3.12 Compliance with Applicable Laws. Except as would not have or would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, the Company and the Company Subsidiaries are in compliance with all applicable Laws and all Permits applicable to the business and operations of the Company and the Company Subsidiaries. This Section 3.12 does not relate to Taxes; Company Benefit Plans or Company Benefit Agreements (including their compliance with any applicable Law) or ERISA; or environmental matters; or Intellectual Property, which are addressed in Sections 3.08, 3.09, 3.14 and 3.17, respectively.

SECTION 3.13 Takeover Statutes. Assuming that the representations and warranties of Parent and Merger Sub contained in Section 4.09 are true and correct, the Merger is not subject to any "fair price," "moratorium," "control-share acquisition," "affiliated transaction" or any other antitakeover statute or regulation (each, a "**Takeover Statute**") or any antitakeover provision in the Company Articles or Company Bylaws.

SECTION 3.14 Environmental Matters.

(a) Except for matters that have not had and would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect:

(i) the Company and the Company Subsidiaries are in compliance with all Environmental Laws;

(ii) with respect to Permits under Environmental Law that are necessary to conduct the respective operations of the Company or the Company Subsidiaries as currently conducted ("**Environmental Permits**"), (1) the Company and each of the Company Subsidiaries have obtained and are in compliance with, or have filed timely applications for, all such Environmental Permits, (2) all such Environmental Permits are valid and in good standing and (3) neither the Company nor any Company Subsidiary has received written notice from any Governmental Entity seeking to modify, revoke or terminate, any such Environmental Permits;

(iii) there are no Environmental Claims pending or, to the Knowledge of the Company, threatened in writing against the Company or any Company Subsidiary; and

(iv) to the Knowledge of the Company, there are and have been no Releases of Hazardous Materials at any property currently owned, leased or operated by the Company or any Company Subsidiary that would reasonably be expected to form the basis of any Environmental Claim against the Company or any Company Subsidiary.

(b) The representations and warranties contained in this Section 3.14 are the sole and exclusive representations and warranties of the Company relating to Environmental Permits, Environmental Laws, Environmental Claims, Releases, Hazardous Materials or other environmental matters.

SECTION 3.15 Contracts.

(a) Except for this Agreement, Company Benefit Plans and Company Benefit Agreements, as of the date of this Agreement, neither the Company nor any Company Subsidiary is a party to any Contract required to be filed by the Company as a "material contract" pursuant to Item 601(b)(10) of Regulation S-K under the Securities Act (a "**Filed Company Contract**") that has not been so filed.

(b) Except as would not have or would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, (i) each Filed Company Contract is a valid, binding and legally enforceable obligation of the Company or one of the Company Subsidiaries, as the case may be, and, to the Knowledge of the Company, of the other parties thereto, subject in all respects to the Bankruptcy and Equity Exceptions, (ii) to the Knowledge of the Company, each such Filed Company Contract is in full force and effect and (iii) as of the date hereof, none of the Company or any Company Subsidiary is (with or without notice or lapse of time, or both) in breach or default under any such Filed Company Contract and, to the Knowledge of the Company, no other party to any such Filed Company Contract is (with or without notice or lapse of time, or both) in breach or default thereunder.

SECTION 3.16 Real Property. Except as would not have or would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect, each of the Company and the Company Subsidiaries has either good title, in fee or valid leasehold, easement or other rights, to the land, buildings, wires, pipes, structures and other improvements thereon and fixtures thereto necessary to permit it to conduct its business as currently conducted. This Section 3.16 does not relate to environmental matters; or Intellectual Property, which are addressed in Section 3.14 and Section 3.17, respectively.

SECTION 3.17 Intellectual Property.

(a) Except as would not have or would not be reasonably expected to have, individually or in the aggregate, a Company Material Adverse Effect, to the Knowledge of the Company, (i) the Company and the Company Subsidiaries have the right to use all material Intellectual Property used in their business as presently conducted, and (ii) no person is violating any material Intellectual Property owned by the Company and the Company Subsidiaries.

(b) The representations and warranties contained in this Section 3.17 are the sole and exclusive representations and warranties of the Company relating to Intellectual Property, and no other representation or warranty of the Company contained herein shall be construed to relate to Intellectual Property.

SECTION 3.18 Insurance. As of the date hereof, except as would not have or would not be reasonably likely to have, individually or in the aggregate, a Company Material Adverse Effect, all material fire and casualty, general liability, director and officer, and business interruption insurance policies maintained by the Company or any of its Subsidiaries ("**Insurance Policies**") are in full force and effect and all premiums due with respect to all Insurance Policies have been paid.

SECTION 3.19 Regulatory Status.

(a) Except as set forth in Section 3.19(a)(i) of the Company Disclosure Letter, none of the Company Subsidiaries is regulated as a public utility under the FPA. Except for the Company Subsidiaries set forth in Section 3.19(a)(ii) of the Company Disclosure Letter (the "**Utility Subsidiaries**"), none of the Company Subsidiaries are regulated as a public utility or gas utility under the applicable Law of any state.

(b) All filings (except for immaterial filings) required to be made by the Company or any Company Subsidiary since January 1, 2015, with the FERC, the FCC and the State Commissions, as the case may be, have been made, including all forms, statements, reports, agreements and all documents, exhibits, amendments and supplements appertaining thereto, including all rates, tariffs and related documents, and all such filings complied, as of their respective dates, with all applicable requirements of applicable statutes and the rules and regulations promulgated thereunder, except for filings the failure of which to make or the failure of which to make in compliance with all applicable requirements of applicable statutes and the rules and regulations promulgated thereunder, would not reasonably be expected to have, individually or in the aggregate, a Company Material Adverse Effect.

SECTION 3.20 Brokers' Fees and Expenses. Except for the Person set forth in Section 3.20 of the Company Disclosure Letter (such Person, the "**Company Financial Advisor**"), the fees and expenses of which will be paid by the Company, no broker, investment banker, financial advisor or other Person is entitled to any broker's, finder's, financial advisor's or other similar fee or commission in connection with the Merger based upon arrangements made by or on behalf of the Company.

SECTION 3.21 Opinion of Financial Advisor. The Company Board has received an opinion of the Company Financial Advisor to the effect that, as of the date of such opinion and based upon and subject to the various matters, limitations, qualifications and assumptions set forth therein, the Merger Consideration to be paid to the holders of shares of Company Common Stock pursuant to this Agreement is fair from a financial point of view to such holders.

SECTION 3.22 No Additional Representations. Except for the representations and warranties expressly set forth in Article IV (as modified by the Parent Disclosure Letter), the Company specifically acknowledges and agrees that neither Parent nor any of its Affiliates, Representatives or shareholders or any other Person makes, or has made, any other express or implied representation or warranty whatsoever (whether at law (including at common law or by statute) or in equity). Except for the representations and warranties expressly set forth in this Article III (as modified by the Company Disclosure Letter), the Company hereby expressly disclaims and negates (a) any other express or implied representation or warranty whatsoever (whether at law (including at common law or by statute) or in equity), including with respect to (i) the Company or the Company Subsidiaries or any of the Company's or the Company's Subsidiaries respective businesses, assets, employees, Permits, liabilities, operations, prospects or condition (financial or otherwise) or (ii) any opinion, projection, forecast, statement, budget, estimate, advice or other information (including information with respect to filings with and consents of any Governmental Entity (including the FERC, the FCC and the State Commissions) or information with respect to the future revenues, results or operations (or any component thereof), cash flows, financial condition (or any component thereof) or the future business and operations of the Company or the Company Subsidiaries, as well as any other business plan and cost-related plan information of the Company or the Company Subsidiaries), made, communicated or furnished (orally or in writing), or to be made, communicated or furnished (orally or in writing), to Parent, its Affiliates or its Representatives, in each case, whether made by the Company or any of its Affiliates, Representatives or shareholders or any other Person (this clause (ii), collectively, "**Company Projections**") and (b) all liability and responsibility for any such other representation or warranty or any such Company Projection.

ARTICLE IV

REPRESENTATIONS AND WARRANTIES OF PARENT AND MERGER SUB

Except as set forth in the disclosure letter delivered by Parent to the Company concurrently with the execution and delivery by Parent and Merger Sub of this Agreement (the "**Parent Disclosure Letter**"), Parent and Merger Sub represent and warrant to the Company as follows:

SECTION 4.01 Organization, Standing and Power. Each of Parent and Merger Sub is duly organized, validly existing and in active status or good standing, as applicable, under the laws of the jurisdiction in which it is organized (in the case of active status or good standing, to the extent such jurisdiction recognizes such concept). Each of Parent and Merger Sub has all requisite entity power and authority to own, operate, lease or otherwise hold its properties and assets and to conduct its businesses as presently conducted, except where the failure to have such power or authority would not have or would not reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect. Each of Parent and Merger Sub is duly qualified or licensed to do business in each jurisdiction where the nature of its business or the ownership, operation or leasing of its properties make such qualification necessary, except in any such jurisdiction where the failure to be so qualified or licensed would not have or would not reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect.

SECTION 4.02 Authority; Execution and Delivery; Enforceability. Each of Parent and Merger Sub has all requisite power and authority to execute and deliver this Agreement, to perform its covenants and agreements hereunder and to consummate the Merger. The board of directors of Parent has adopted resolutions (a) determining that it is in the best interests of Parent and its shareholders, and declaring it advisable, for Parent to enter into this Agreement and (b) adopting this Agreement and approving Parent's execution, delivery and performance of this Agreement and the consummation of the transactions contemplated by this Agreement. Such resolutions have not been amended or withdrawn as of the date of this Agreement. The board of directors of Merger Sub has adopted resolutions determining that it is in the best interests of Merger Sub and its shareholder, and declaring it advisable, for Merger Sub to enter into this Agreement, (ii) adopting this Agreement and approving Merger Sub's execution, delivery and performance of this Agreement and the consummation of the transactions contemplated by this Agreement and (iii) resolving to recommend that Parent, in its capacity as the sole shareholder of Merger Sub, approve this Agreement. Such resolutions have not been amended or withdrawn as of the date of this Agreement. No other corporate proceedings on the part of Parent or Merger Sub are necessary to authorize, adopt or approve, as applicable, this Agreement or to consummate the Merger. Parent and Merger Sub have duly executed and delivered this Agreement and, assuming the due authorization, execution and delivery by the Company, this Agreement constitutes the legal, valid and binding obligation of each of Parent and Merger Sub, enforceable against it in accordance with its terms, subject in all respects to the Bankruptcy and Equity Exceptions.

SECTION 4.03 No Conflicts; Consents.

(a) The execution and delivery of this Agreement by Parent and Merger Sub does not, and the performance by each of Parent and Merger Sub of its covenants and agreements and the consummation of the Merger will not, (i) conflict with, or result in any violation of any provision of, the Organizational Documents of Parent or Merger Sub, (ii) subject to obtaining the Consents set forth in Section 4.03(a)(ii) of the Parent Disclosure Letter (the "**Parent Required Consents**" and, together with the Company Required Consents, the "**Required Consents**"), conflict with, result in any violation of, or default (with or without notice or lapse of time, or both) under, or give rise to a right of termination, cancellation or acceleration of any material obligation or to the loss of a material benefit under any material

Contract to which Parent or Merger Sub is a party or by which any of their respective properties or assets is bound or any material Permit applicable to the business of Parent and its Affiliates or (iii) subject to obtaining the Consents referred to in Section 4.03(b) and making the Filings referred to in Section 4.03(b), conflict with, or result in any violation of any provision of, any Judgment or Law, in each case, applicable to Parent or Merger Sub or their respective properties or assets, except for, in the case of the foregoing clauses (ii) and (iii), any matter that would not have or would not be reasonably expected to have, individually or in the aggregate, a Parent Material Adverse Effect.

(b) No Consent of or from, or Filing made to or with, any Governmental Entity, is required to be obtained or made by Parent or any Affiliate of Parent in connection with Parent's and Merger Sub's execution and delivery of this Agreement or their performance of their covenants and agreements hereunder or the consummation of the Merger, except for the following:

(i) compliance with, Filings under and the expiration of any applicable waiting period under the HSR Act;

(ii) (1) Filings with, and the Consent of, the FERC under Section 203 of the FPA, (2) the CFIUS Approval, and Filings with respect thereto, (3) the Filings with, and the Consent of, the State Commissions, (4) pre-approvals of license transfers with the FCC, and (5) and the other Filings and Consents set forth in Section 4.03(b)(ii) of the Parent Disclosure Letter (the Consents and Filings set forth in Section 4.03(b)(i) and this Section 4.03(b)(ii), collectively, the "**Parent Required Statutory Approvals**" and, together with the Company Required Statutory Approvals, the "**Required Statutory Approvals**");

(iii) the Parent Required Consents;

(iv) the filing of the Certificate of Merger with the Office of the Secretary of State of the State of Kansas and appropriate documents with the relevant authorities of the other jurisdictions in which Parent and the Company are qualified to do business;

(v) Filings and Consents as are required to be made or obtained under state or federal property transfer Laws or Environmental Laws; and

(vi) such other Filings and Consents the failure of which to make or obtain would not have or would not reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect.

SECTION 4.04 Litigation. There is no Claim before any Governmental Entity pending or, to the Knowledge of Parent, threatened against Parent, Merger Sub or any Affiliate of Parent that has had or would reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect. There is no Judgment outstanding against or, to the Knowledge of Parent, investigation by any Governmental Entity of Parent, Merger Sub or any Affiliate of Parent or any of their respective properties or assets that has had or would reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect.

SECTION 4.05 Compliance with Applicable Laws. Except as would not have or would not reasonably be expected to have, individually or in the aggregate, a Parent Material Adverse Effect, Parent and Merger Sub are in compliance with all applicable Laws and material Permits applicable to the business and operations of Parent and Parent's Affiliates.

SECTION 4.06 Financing. Parent has delivered to the Company true and complete fully executed copies of (a) the commitment letter, dated as of February 3, 2016, among Guarantor and Canadian Imperial Bank of Commerce, The Bank of Nova Scotia, JPMorgan Chase Bank, N.A., Wells Fargo Bank, National Association, and Wells Fargo Securities, LLC (the "**Commitment Letter**") and (b) the fee letter, among Guarantor and Canadian Imperial Bank of Commerce, The Bank of Nova Scotia, JPMorgan Chase Bank, N.A., Wells Fargo Bank, National Association, and Wells Fargo Securities, LLC, dated as of February 3, 2016 (as redacted to remove only the fee amounts, pricing caps, the rates and amounts included in the "market flex," the "**Redacted Fee Letter**"), in each case, including all exhibits, schedules, annexes and amendments to such letters in effect as of the date of this Agreement (collectively, the "**Debt Letters**"), pursuant to which and subject to the terms and conditions thereof, each of the parties thereto (other than Guarantor) have severally committed to lend the amounts set forth therein to Guarantor (the provision of such funds as set forth therein, the "**Financing**") for the purposes set forth in such Debt Letters. The Debt Letters have not been amended, restated or otherwise modified or waived prior to the execution and delivery of this Agreement, and the respective commitments contained in the Debt Letters have not been withdrawn, rescinded, amended, restated or otherwise modified in any respect prior to the execution and delivery of this Agreement. As of the execution and delivery of this Agreement, the Debt Letters are in full force and effect and constitute the legal, valid and binding obligation of each of Guarantor and the other parties thereto, subject in each case to the Bankruptcy and Equity Exceptions. There are no conditions precedent or contingencies directly or indirectly related to the funding of the Financing pursuant to the Debt Letters, other than as expressly set forth in the Debt Letters. At the Closing, Parent and Merger Sub will have sufficient funds to pay all of Parent's and Merger Sub's obligations under this Agreement, including the payment of the Merger Consideration and all fees and expenses expected to be incurred in connection therewith. As of the date of this Agreement, no event has occurred which, with or without notice, lapse of time or both, would constitute a breach or default on the part of Guarantor under the Debt Letters or any other party to the Debt Letters. As of the date of this Agreement, except for any agreements relating to any alternative equity capital markets financing (which agreements do not contain any terms that would adversely affect the conditionality, enforceability, termination, principal amount or availability of the Financing), there are no side letters or other agreements, Contracts, arrangements or understandings (written or oral) directly or indirectly related to the funding of the Financing other than as expressly set forth in the Debt Letters. Guarantor has fully paid all commitment fees or other fees required to be paid on or prior to the date of this Agreement in connection with the Financing. As of the date of this Agreement, Parent (1) is not aware of any fact, event or other occurrence that makes any of the representations or warranties of Guarantor in any of the Debt Letters inaccurate in any material respect and (2) has no reason to believe that any of the conditions to the Financing contemplated by the Debt Letters will not be satisfied on a timely basis or that the Financing contemplated by the Debt Letters will not be made available on the Closing Date.

SECTION 4.07 Brokers' Fees and Expenses. Except for any Person set forth in Section 4.07 of the Parent Disclosure Letter, the fees and expenses of which will be paid by Parent or its Affiliates, no broker, investment banker, financial advisor or other Person is entitled to any broker's, finder's, financial advisor's or other similar fee or commission in connection with the Merger based upon arrangements made by or on behalf of Parent or Merger Sub or any of their Affiliates.

SECTION 4.08 Merger Sub. The authorized capital stock of Merger Sub consists of 10,000 shares of common stock, par value $1.00 per share. All outstanding shares of capital stock of Merger Sub are duly authorized, validly issued, fully paid and nonassessable. Parent owns all of the outstanding shares of capital stock of Merger Sub. Guarantor owns, directly or indirectly, all of the outstanding shares of capital stock of Parent. Merger Sub has been incorporated solely for the purpose of merging with and into the Company and taking action incident to the Merger and this Agreement. Merger Sub has no assets, liabilities or obligations and has not, since the date of its formation, carried on any business or conducted any operations, except, in each case, as arising from the execution of this Agreement, the performance of its covenants and agreements hereunder and matters ancillary thereto. Parent has approved this Agreement by written consent in its capacity as the sole shareholder of Merger Sub.

SECTION 4.09 Ownership of Company Common Stock; Related Person. Neither Parent, any Subsidiary of Parent nor any other Affiliate of Parent (i) "beneficially owns" (as such term is defined for purposes of Section 13(d) of the Exchange Act) any shares of Company Common Stock or any other Equity Securities or (ii) is a "related person" (as defined in Item 404 of Regulation S-K of the Securities Act) of the Company. Neither Parent, any Subsidiary of Parent nor any of their respective Affiliates are a Person referred to in GCC Section 17-6712.

SECTION 4.10 Regulatory Status. Guarantor is, and prior to the Effective Time Parent may become, a public utility holding company under the Public Utility Holding Company Act of 2005 ("**PUHCA 2005**"). Merger Sub is not a public utility holding company under PUHCA 2005.

SECTION 4.11 Guarantee. Concurrently with the execution of this Agreement, Parent has delivered to the Company a guaranty (the "**Guarantee**"), dated the date hereof, of the Guarantor, guaranteeing the obligations of Parent. The Guarantee is valid and in full force and effect and constitutes the valid and binding obligation of the Guarantor, enforceable in accordance with its terms.

SECTION 4.12 No Additional Representations. Except for the representations and warranties expressly set forth in Article III (as modified by the Company Disclosure Letter), each of Parent and Merger Sub (a) specifically acknowledges and agrees that neither the Company nor any of its Affiliates, Representatives or shareholders nor any other Person makes, or has made, any other express or implied representation or warranty whatsoever (whether at law (including at common law or by statute) or in equity), including with respect to the Company or the Company Subsidiaries or any of the Company's or the Company's Subsidiaries respective businesses, assets, employees, Permits, liabilities, operations, prospects, condition (financial or otherwise) or any Company Projection, and hereby expressly waives and relinquishes any and all rights, Claims or causes of action (whether in contract or in tort or otherwise, or whether at law (including at common law or by statute) or in equity) based on, arising out of or relating to any such other representation or warranty or any Company Projection, (b) specifically acknowledges and agrees to the Company's express disclaimer and negation of any such other representation or warranty or any Company Projection and of all liability and responsibility for any such other representation or warranty or any Company Projection and (c) expressly waives and relinquishes any and all rights, Claims and causes of action (whether in contract or in tort or otherwise, or whether at law (including at common law or by statute) or in equity) against (i) the Company in connection with accuracy, completeness or materiality of any Company Projection and (ii) any Affiliate of the Company or any of the Company's or any such Affiliate's respective Representatives or shareholders or any other Person, and hereby specifically acknowledges and agrees that such Persons shall have no liability or obligations, based on, arising out of or relating to this Agreement or the negotiation, execution, performance or subject matter hereof, including (1) for any alleged nondisclosure or misrepresentations made by any such Person or (2) in connection with accuracy, completeness or materiality of any Company Projection. Each of Parent and Merger Sub acknowledges and agrees that (A) it has conducted to its satisfaction its own independent investigation of the transactions contemplated hereby (including with respect to the Company and the Company Subsidiaries and their respective businesses, operations, assets and liabilities) and, in making its determination to enter into this Agreement and proceed with the transactions contemplated hereby, has relied solely on the results of such independent investigation and the representations and warranties of the Company expressly set forth in Article III (as modified by the Company Disclosure Letter), and (B) except for the representations and warranties of the Company expressly set forth in Article III (as modified by the Company Disclosure Letter), it has not relied on, or been induced by, any representation, warranty or other statement of or by the Company or any of its Affiliates, Representatives or shareholders or any other Person, including any Company Projection or with respect to the Company or the Company Subsidiaries or any of the Company's or the Company's Subsidiaries respective businesses, assets, employees, Permits, liabilities, operations, prospects or condition (financial or otherwise) or any Company Projection, in determining to enter into this Agreement and proceed with the transactions contemplated hereby.

ARTICLE V

COVENANTS RELATING TO CONDUCT OF BUSINESS

SECTION 5.01 Conduct of Business.

(a) Conduct of Business by the Company. Except for matters set forth in Section 5.01 of the Company Disclosure Letter or otherwise contemplated or required by this Agreement, or as required by a Governmental Entity (including pursuant to a Judgment issued by the FERC, the FCC or any State Commission) or by applicable Law, or as contemplated by the Proceedings, or with the prior written consent of Parent (which consent shall not be unreasonably withheld, conditioned or delayed), from the date of this Agreement until the Effective Time, the Company shall use commercially reasonable efforts to, and to cause each Company Subsidiary to, (x) conduct its business in the ordinary course of business in all material respects and (y) to the extent consistent with the foregoing clause (x), preserve intact, in all material respects, its business organization and existing relationships with Governmental Entities. In addition, and without limiting the generality of the foregoing, except as set forth in the Company Disclosure Letter or otherwise contemplated or required by this Agreement, or as required by a Governmental Entity (including pursuant to a Judgment issued by the FERC, the FCC or any State Commission) or by applicable Law, or as contemplated by the Proceedings, or with the prior written consent of Parent (which consent shall not be unreasonably withheld, conditioned or delayed), from the date of this Agreement until the Effective Time, the Company shall not, and shall not permit any Company Subsidiary to, do any of the following:

(i) declare, set aside or pay any dividends on, or make any other distributions (whether in cash, stock or property or any combination thereof) in respect of, any of its capital stock, other equity interests or voting securities, except for (1) quarterly cash dividends payable by the Company or any Company Subsidiary in respect of shares of Company Common Stock on a schedule and in an amount per share of Company Common Stock consistent with the Company's past practices but without increase in the amount per share, (2) dividends and distributions by a direct or indirect Company Subsidiary to its parent and (3) a "stub period" dividend to holders of record of Company Common Stock as of immediately prior to the Effective Time equal to the product of (A) the number of days from the record date for payment of the last quarterly dividend paid by the Company prior to the Effective Time, multiplied by (B) a daily dividend rate determined by dividing the amount of the last quarterly dividend prior to the Effective Time by ninety-one (91);

(ii) amend any of its Organizational Documents (except for immaterial or ministerial amendments);

(iii) except as permitted by Section 5.01(a)(v) or for transactions among the Company and the Company Subsidiaries or among the Company Subsidiaries, split, combine, consolidate, subdivide or reclassify any of its capital stock, other equity interests or voting securities, or securities convertible into or exchangeable or exercisable for capital stock or other equity interests or voting securities, or issue or authorize the issuance of any other securities in respect of, in lieu of or in substitution for its capital stock, other equity interests or voting securities;

(iv) repurchase, redeem or otherwise acquire, or offer to repurchase, redeem or otherwise acquire, any capital stock or voting securities of, or equity interests in, the Company or any Company Subsidiary or any securities of the Company or any Company Subsidiary convertible into or exchangeable or exercisable for capital stock or voting securities of, or equity interests in, the Company or any Company Subsidiary, or any warrants, calls, options or other rights to acquire any such capital stock, securities or interests, except for (1) the acquisition by the Company of shares of Company Common Stock in the open market to satisfy its obligations under all Company Benefit Plans or under the Company's dividend reinvestment and direct stock purchase plan (the "**Company DRIP**"), (2) the withholding of shares of Company Common Stock to satisfy Tax obligations with respect to awards granted pursuant to the Company Benefit Plans and (3) the acquisition by the Company of awards granted pursuant to the Company Benefit Plans in connection with the forfeiture of such awards;

(v) issue, deliver, sell, grant, pledge or otherwise encumber or subject to any Lien any Equity Securities or Company Voting Debt, in each case, except for the issuance of (1) Equity Securities pursuant to the Company Benefit Plans as permitted by Section 5.01(a)(vi), (2) shares of Company Common Stock pursuant to Director Stock Units, Time-Vested Restricted Stock Awards and Performance-Based Restricted Stock Awards outstanding on the date of this Agreement and in accordance with their terms on the date of this Agreement or granted after the date of this Agreement pursuant to the foregoing clause (1), or (3) shares of Company Common Stock under the Company DRIP;

(vi) (1) grant to any Company Personnel any increase in compensation or benefits except in the ordinary course of business and consistent with past practices, (2) grant to Company Personnel increases, in the aggregate, in change-in-control, severance, retention or termination pay, (3) enter into or amend any change-in-control, severance, retention or termination agreement with any Company Personnel, except in order to effect changes permitted by clause (2) of this Section 5.01(a)(vi), (4) establish, adopt, enter into, amend in any material respect or terminate any Company Union Contract or Company Benefit Plan or Company Benefit Agreement (or any plan or agreement that would be a Company Union Contract, Company Benefit Plan or Company Benefit Agreement if in existence on the date hereof), in each case, except in the ordinary course of business consistent with past practices or (5) take any action to accelerate the time of vesting, funding or payment of any compensation or benefits under any Company Benefit Plan or Company Benefit Agreement, except in the case of the foregoing clauses (1) through (5) for actions required pursuant to the terms of any Company Benefit Plan or Company Benefit Agreement existing on the date hereof, or as required by the terms and conditions of this Agreement;

(vii) make any material change in financial accounting methods, principles or practices, except to the extent as may have been required by a change in applicable Law or GAAP or by any Governmental Entity (including the SEC or the Public Company Accounting Oversight Board);

(viii) make any acquisition or disposition of a material asset or business (including by merger, consolidation or acquisition of stock or assets), except for (1) any acquisition or disposition for consideration that is individually not in excess of $5,000,000 and in the aggregate not in excess of $20,000,000 or (2) any disposition of obsolete or worn-out equipment in the ordinary course of business;

(ix) incur any Indebtedness, except for (1) Indebtedness incurred in the ordinary course of business, (2) as reasonably necessary to finance any capital expenditures permitted under Section 5.01(a)(x), (3) Indebtedness in replacement of existing Indebtedness, (4) guarantees by the Company of existing Indebtedness of any wholly owned Company Subsidiary, (5) guarantees and other credit support by the Company of obligations of any Company Subsidiary in the ordinary course of business consistent with past practice, (6) borrowings under existing revolving credit facilities (or replacements thereof on comparable terms) or existing commercial paper programs in the ordinary course of business or (7) Indebtedness in amounts necessary to maintain the capital structure of the Company Subsidiaries, as authorized by the State Commissions, and to maintain the present capital structure of the Company consistent with past practice in all material respects;

(x) make, or agree or commit to make, any capital expenditure, except for capital expenditures (1) in the ordinary course of business, (2) in accordance with the capital plan set forth in Section 5.01(a)(x) of the Company Disclosure Letter, plus a 10% aggregate variance or (3) with respect to any capital expenditure not addressed by the foregoing clauses (1) or (2), not to exceed $15,000,000 in any twelve (12) month period;

(xi) (1) modify or amend in any material respect, or terminate or waive any material right under, any Filed Company Contract (except for (A) any modification, amendment, termination or waiver in the ordinary course of business or (B) a termination without material penalty to the Company or the appropriate Company Subsidiary) or (2) without limiting Parent's obligations under Section 6.03, enter into any Contract that, from and after the Closing, purports to bind Parent or any of its Affiliates (other than the Company and the Company Subsidiaries);

(xii) make or change any material Tax election, change any material method of Tax accounting, settle or compromise any material Tax liability or refund or amend any material Tax Return, in each case, except as may be required by a change in applicable Law or GAAP or by any Governmental Entity;

(xiii) waive, release, assign, settle or compromise any material Claim against the Company or any Company Subsidiary, except for (1) waivers, releases, assignments, settlements or compromises in the ordinary course of business or (2) waivers, releases, assignments, settlements or compromises that (A) with respect to the payment of monetary damages, the amount of monetary damages to be paid by the Company or the Company Subsidiaries does not exceed (I) the amount with respect thereto reflected on the Company Financial Statements (including the notes thereto) or (II) $10,000,000, in the aggregate, in excess of the proceeds received or to be received from any insurance policies in connection with such payment or (B) with respect to any nonmonetary terms and conditions thereof, would not have or would not reasonably be expected to have, individually or in the aggregate, a material effect on the continuing operations of the Company and the Company Subsidiaries (taken as a whole); or

(xiv) enter into any Contract to do any of the foregoing.

(b) Emergencies. Notwithstanding anything to the contrary herein, the Company may, and may cause any Company Subsidiary to, take reasonable actions in compliance with applicable Law (i) with respect to any operational emergencies (including any restoration measures in response to any hurricane, tornado, ice storm, tsunami, flood, earthquake or other natural disaster or weather-related event, circumstance or development), equipment failures, outages or an immediate and material threat to the health or safety of natural Persons or (ii) as the Company deems prudent based on Good Utility Practice.

(c) No Control of the Company's Business. Parent acknowledges and agrees that (i) nothing contained herein is intended to give Parent, directly or indirectly, the right to control or direct the operations of the Company or any Company Subsidiary prior to the Effective Time and (ii) prior to the Effective Time, the Company shall exercise, consistent with the terms and conditions of this Agreement, complete control and supervision over its and the Company Subsidiaries' respective operations.

(d) Advice of Changes. Each of Parent and the Company shall promptly advise the other orally and in writing of any change or event that would prevent any of the conditions precedent described in Article VII from being satisfied.

SECTION 5.02 Proceedings. Between the date of this Agreement and the Closing, the Company and the Company Subsidiaries may (a) pursue the rate cases and other proceedings set forth in Section 5.02 of the Company Disclosure Letter, (b) initiate and pursue other rate cases and proceedings with Governmental Entities; provided that the prior written consent of Parent (such consent not to be unreasonably withheld, delayed or conditioned) shall be required to the extent any such other rate case or proceeding would reasonably be expected to result in an outcome that would be materially adverse to the Company and the Company Subsidiaries, taking into account the requests made by the Company and the Company subsidiaries in such rate case or proceeding and the resolution of similar recent rate cases or proceedings by the Company and the Company Subsidiaries, (c) initiate any other proceeding with Governmental Entities in the ordinary course of business (the foregoing clauses (a), (b) and (c), collectively, the "**Proceedings**") and (d) notwithstanding anything to the contrary herein, initiate any other proceedings with Governmental Entities or take any other action contemplated by or described in any filings or other submissions filed or submitted in connection with the Proceedings prior to the date of this Agreement. Notwithstanding the foregoing, (1) except as set forth in clause (2) of this sentence, without the prior written consent of Parent (such consent not to be unreasonably withheld, delayed or conditioned), the Company and the Company Subsidiaries will not enter into any settlement or stipulation in respect of any Proceeding if such settlement or stipulation would result in an outcome that would be materially adverse to the Company and the Company Subsidiaries, taking into account the requests made by the Company and the Company subsidiaries in the Proceeding and the resolution of similar recent proceedings by the Company and the Company Subsidiaries and (2) nothing herein or elsewhere in this Agreement shall prohibit the Company from initiating, continuing to pursue, settling or entering into any stipulation with respect to any (i) fuel adjustment filing, rate case or other proceeding, (ii) purchased gas adjustment filing, rate case or other proceeding, (iii) FERC formula rate filing, rate case or other proceeding or (iv) filing, rate case or other proceeding with the State Commissions in the States of Arkansas, Kansas or Oklahoma.

SECTION 5.03 No Solicitation by the Company; Company Board Recommendation.

(a) The Company shall not, shall cause its Affiliates not to, and shall use reasonable efforts to cause its and their respective officers, directors, principals, partners, managers, members, attorneys, accountants, agents, employees, consultants, financial advisors or other authorized representatives (collectively, "**Representatives**") not to, (i) directly or indirectly solicit, initiate or knowingly encourage, induce or facilitate any Company Takeover Proposal or any inquiry or proposal that would reasonably be expected to lead to a Company Takeover Proposal, in each case, except for this Agreement and the transactions contemplated hereby, or (ii) directly or indirectly participate in any discussions or negotiations with any Person (except for the Company's Affiliates and its and their respective Representatives or Parent and Parent's Affiliates and its and their respective Representatives) regarding, or furnish to any such Person, any nonpublic information with respect to, or cooperate in any way with any such Person with respect to, any Company Takeover Proposal or any inquiry or proposal that would reasonably be expected to lead to a Company Takeover Proposal. The Company shall, and shall cause its Affiliates and its and their respective Representatives to, immediately cease and cause to be terminated all existing discussions or negotiations with any Person (except for the Company's Affiliates and its and their respective Representatives or Parent and Parent's Affiliates and its and their respective Representatives) conducted heretofore with respect to any Company Takeover Proposal, request the prompt return or destruction of all confidential information previously furnished and immediately terminate all physical and electronic data room access previously granted to any such Person or its Representatives. Notwithstanding anything to the contrary herein, at any time prior to obtaining the Company Shareholder Approval, in response to the receipt of a *bona fide* written Company Takeover Proposal made after the date of this Agreement that does not result from a breach (other than an immaterial breach) of this Section 5.03(a) by the Company and that the Company Board determines in good faith (after consultation with outside legal counsel and a financial advisor) constitutes or could reasonably be expected to lead to a Superior Company Proposal, the Company and its Representatives may (1) furnish information with respect to the Company and the Company Subsidiaries to the Person making such Company Takeover Proposal (and its Representatives) (provided that all such information has previously been provided to Parent or is provided to Parent prior to or substantially concurrently with the provision of such information to such Person) pursuant to a customary confidentiality agreement no less restrictive, in the aggregate, than the Confidentiality Agreement and (2) participate in discussions regarding the terms of such Company Takeover Proposal, including terms of a Company Acquisition Agreement with respect thereto, and the negotiation of such terms with the Person making such Company Takeover Proposal (and such Person's Representatives). Notwithstanding anything to the contrary herein, the Company may grant a waiver, amendment or release under any confidentiality or standstill agreement to the extent necessary to allow a confidential Company Takeover Proposal to be made to the Company or the Company Board so long as the Company promptly notifies Parent thereof after granting any such waiver, amendment or release.

(b) Except as set forth in Section 5.03(a), Section 5.03(c) and Section 5.03(e), neither the Company Board nor any committee thereof shall (i) withdraw, change, qualify, withhold or modify in any manner adverse to Parent, or propose publicly to withdraw, change, qualify, withhold or modify in any manner adverse to Parent, the Company Board Recommendation, (ii) adopt, approve or recommend, or propose publicly to adopt, approve or recommend, any Company Takeover Proposal, (iii) fail to include in the Proxy Statement the Company Board Recommendation or (iv) take any formal action or make any recommendation or public statement in connection with a tender offer or exchange offer (except for a recommendation against such offer or a customary "stop, look and listen" communication of the type contemplated by Rule 14d-9(f) under the Exchange Act) (any action in the foregoing clauses (i)–(iv) being referred to as a "**Company Adverse Recommendation Change**"). Except as set forth in Section 5.03(a), Section 5.03(c) and Section 5.03(e), neither the Company Board nor any committee thereof shall authorize, permit, approve or recommend, or propose publicly to authorize, permit, approve or recommend, or allow the Company or any of its Affiliates to execute or enter into, any letter of intent, memorandum of understanding, agreement in principle, agreement or commitment constituting, or that would reasonably be expected to lead to, any Company Takeover Proposal, or requiring, or that would reasonably be expected to cause, the Company to abandon or terminate this Agreement (a "**Company Acquisition Agreement**").

(c) Notwithstanding anything to the contrary herein, at any time prior to obtaining the Company Shareholder Approval, the Company Board may make a Company Adverse Recommendation Change if (i) a Company Intervening Event has occurred or (ii) the Company has received a Superior Company Proposal that does not result from a breach (other than an immaterial breach) of Section 5.03(a) by the Company and, in each case, if the Company Board determines in good faith (after consultation with outside legal counsel) that the failure to effect a Company Adverse Recommendation Change as a result of the occurrence of such Company Intervening Event or in response to the receipt of such Superior Company Proposal, as the case may be, would reasonably likely be inconsistent with the Company Board's fiduciary duties under applicable Law; provided, however, that the Company Board shall not make such Company Adverse Recommendation Change unless (1) the Company Board has provided prior written notice to Parent (a "**Recommendation Change Notice**") that it is prepared to effect a Company Adverse Recommendation Change in response to the occurrence of a Company Intervening Event or the receipt of a Superior Company Proposal, which notice shall, in the case of a Company Adverse Recommendation Change in response to the receipt of a Superior Company Proposal, at the Company's option, either attach the most current draft of any Company Acquisition Agreement with respect to such Superior Company Proposal or include a summary of the material terms and conditions of such Superior Company Proposal (including the identity of the Person making such Superior Company Proposal), (2) if requested by Parent, during the three (3) Business Day period after delivery of the Recommendation Change Notice, the Company and its Representatives negotiate in good faith with Parent and its Representatives regarding any revisions to this Agreement and (3) at the end of such three (3) Business Day period and taking into account any changes to the terms of this Agreement committed to in writing by Parent (it being understood and agreed that if there has been any subsequent amendment to any material term of such Superior Company Proposal, the Company Board shall provide a new Recommendation Change Notice and an additional three (3) Business Day period from the date of such notice shall apply), the Company Board determines in good faith (after consultation with outside legal counsel) that the failure to make such a Company Adverse Recommendation Change would reasonably likely be inconsistent with its fiduciary duties under applicable Law.

(d) The Company shall promptly (and in any event no later than the later of (i) twenty-four (24) hours or (ii) 5 p.m. New York City time on the next Business Day) advise Parent orally and in writing of any Company Takeover Proposal and the material terms and conditions of any such Company Takeover Proposal (including the identity of the Person making such Company Takeover Proposal). The Company shall keep Parent reasonably informed in all material respects on a reasonably current basis of the material terms and status (including any change to the terms thereof) of any Company Takeover Proposal.

(e) Nothing contained in this Section 5.03 shall prohibit the Company from (i) complying with Rule 14d-9 and Rule 14e-2 promulgated under the Exchange Act or (ii) making any disclosure to the shareholders of the Company if, in the good-faith judgment of the Company Board (after consultation with outside legal counsel) failure to so disclose would reasonably likely be inconsistent with its obligations under applicable Law.

(f) For purposes of this Agreement:

(i) "**Company Takeover Proposal**" means any proposal or offer (whether or not in writing), with respect to any (1) merger, consolidation, share exchange, other business combination, recapitalization, liquidation, dissolution or similar transaction involving the Company, (2) sale, lease, contribution or other disposition, directly or indirectly (including by way of merger, consolidation, share exchange, other business combination, partnership, joint venture, sale of capital stock of or other equity interests in a Company Subsidiary or otherwise) of any business or assets of the Company or the Company Subsidiaries representing 20% or more of the consolidated revenues, net income or assets of the Company and the Company Subsidiaries, taken as a whole, (3) issuance, sale or other disposition, directly or indirectly, to any Person (or the shareholders of any Person) or group of securities (or options, rights or warrants to purchase, or securities convertible into or exchangeable for, such securities) representing 20% or more of the voting power of the Company, (4) transaction (including any tender offer or exchange offer) in which any Person (or the shareholders of any Person) would acquire (in the case of a tender offer or exchange offer, if consummated), directly or indirectly, beneficial ownership, or the right to acquire beneficial ownership, or formation of any group which beneficially owns or has the right to acquire beneficial ownership of, 20% or more of any class of capital stock of the Company or (5) any combination of the foregoing.

(ii) "**Superior Company Proposal**" means a *bona fide* written Company Takeover Proposal (provided that for purposes of this definition, the applicable percentage in the definition of Company Takeover Proposal shall be "more than 50%" rather than "20% or more"), which the Company Board determines in good faith, after consultation with outside legal counsel and a financial advisor, and taking into account the legal, financial, regulatory and other aspects of such Company Takeover Proposal and such other factors that are deemed relevant by the Company Board, is more favorable to the holders of Company Common Stock than the transactions contemplated by this Agreement (after taking into account any proposed revisions to the terms of this Agreement that are committed to in writing by Parent (including pursuant to Section 5.03(c)).

(iii) "**Company Intervening Event**" means any material fact, circumstance, effect, change, event or development that (1) is unknown to or by the Company Board as of the date hereof (or if known, the magnitude or material consequences of which were not known or understood by the Company Board as of the date of this Agreement) and (2) becomes known to or by the Company Board prior to obtaining the Company Shareholder Approval; provided, however, that neither a Company Takeover Proposal nor or any matter relating thereto or consequence thereof shall constitute a Company Intervening Event.

SECTION 5.04 Financing.

(a) Parent shall, and shall cause its Affiliates to, take, or cause to be taken, all actions, and to do, or cause to be done, all things necessary to consummate the Financing, or any Substitute Financing, as promptly as possible following the date of this Agreement (and, in any event, no later than the Closing Date), including (i) (1) maintaining in effect the Debt Letters and complying with all of their respective obligations thereunder and (2) negotiating, entering into and delivering definitive agreements with respect to the Financing reflecting the terms contained in the Debt Letters (or with other terms agreed by Parent or its Affiliates and the Financing Parties, subject to the restrictions on amendments of the Debt Letters set forth below), so that such agreements are in effect no later than the Closing, and (ii) satisfying on a timely basis all the conditions to the Financing and the definitive agreements related thereto that are applicable to Parent and its Affiliates.

(b) In the event that all conditions set forth in Sections 7.01 and 7.03 have been satisfied or waived or, upon funding shall be satisfied or waived, Parent and its Affiliates shall cause the Persons providing the Financing (the "**Financing Parties**") to fund on the Closing Date the Financing, to the extent the proceeds thereof are required to consummate the Merger and the other transactions contemplated hereby, and shall enforce its rights under the Debt Letters (including in the event of any breach or purported breach thereof and including by taking enforcement action to cause such lenders and the other Financing Parties to fund such Financing). Parent shall not, and shall cause its Affiliates not to, take or refrain from taking, directly or indirectly, any action that would reasonably be expected to result in a failure of any of the conditions contained in the Debt Letters or in any definitive agreement related to the Financing. Parent shall not, and shall cause its Affiliates not to, object to the utilization of any "market flex" provisions by any Financing Party.

(c) Parent shall keep the Company reasonably informed on a current and timely basis of the status of the efforts of Parent or its Affiliates to obtain the Financing and to satisfy the conditions thereof, including advising and updating the Company, in a reasonable level of detail, with respect to status, proposed closing date and material terms of the definitive documentation related to the Financing, providing copies of then current drafts of the credit agreement and other primary definitive documents and giving the Company prompt notice of any material change (adverse or otherwise) with respect to the Financing. Without limiting the foregoing, Parent shall notify the Company promptly (and in any event within one (1) Business Day) if at any time prior to the Closing Date:

(i) any Debt Letter expires or is terminated for any reason (or if any Person attempts or purports to terminate or repudiate any Debt Letter, whether or not such attempted or purported termination or repudiation is valid);

(ii) Parent or any of its Affiliates obtains knowledge of any breach or default or any threatened breach or default (or any event or circumstance that, with or without due notice, lapse of time or both, would reasonably be expected to give rise to any breach or default) by any party to any Debt Letter or any definitive document related to the Financing of any provisions of the Debt Letters or any definitive document related to the Financing;

(iii) Parent or any of its Affiliates receives any communication (written or oral) from any Person with respect to any (1) actual, potential or threatened breach, default, termination or repudiation by any party to the Debt Letters or any definitive document related to the Financing of any provisions of the Debt Letters or any definitive document related to the Financing or (2) dispute or disagreement between or among any parties to the Debt Letters;

(iv) any Financing Party refuses to provide or expresses (orally or in writing) an intent to refuse to provide all or any portion of the Financing contemplated by the Debt Letters on the terms set forth therein (or expresses (orally or in writing) that such Person does not intend to enter into all or any portion of definitive documentation related to the Financing or to consummate the transactions contemplated thereby); or

(v) there occurs any event or development that could reasonably be expected to adversely impact the ability of Parent or any of its Affiliates to obtain all, or any portion of, the Financing contemplated by the Debt Letters on the terms and conditions, in the manner or from the sources contemplated by any of the Debt Letters or the definitive documents related to the Financing or if at any time for any other reason Parent no longer believes in good faith that it will be able to obtain all or any portion of the Financing on the terms and conditions, in the manner or from the sources contemplated by any of the Debt Letters or the definitive documents related to the Financing.

(d) As soon as reasonably practicable (but in any event within two (2) Business Days after the date the Company delivers to Parent a written request therefor), Parent shall provide any information reasonably requested by the Company relating to any circumstance referred to in Section 5.04(c)(i)–(v) of the immediately preceding sentence.

(e) Parent or its Affiliates may amend, modify, terminate, assign or agree to any waiver under the Debt Letters (including to add lenders, arrangers, agents, bookrunners, managers and other financing sources) without the prior written approval of the Company; provided that Parent shall not, and shall cause its Affiliates not to, without Company's prior written consent, permit any such amendment, modification, assignment, termination or waiver to be made to, or consent to any waiver of, any provision of or remedy under the Debt Letters which would (1) reduce the aggregate amount of the Financing (including by increasing the amount of fees to be paid or original issue discount), (2) impose new or additional conditions to the Financing or otherwise expand or render more burdensome to Parent or its Affiliates any of the conditions to the Financing or (3) otherwise expand, amend, modify or waive any provision of the Debt Letters in a manner that in any such case would reasonably be expected to (A) delay or make less likely the funding of the Financing (or satisfaction of the conditions to the Financing) on the Closing Date, (B) adversely impact the ability of Parent or its Affiliates to enforce its rights against the Financing Parties or any other parties to the Debt Letters or the definitive agreements with respect thereto or (C) adversely affect the ability of Parent to timely consummate the Merger and the other transactions contemplated hereby. In the event that new debt or equity commitment letters or fee letters are entered into in accordance with any amendment, replacement, supplement or other modification of the Debt Letters permitted pursuant to this Section 5.04(e), such new commitment letters or fee letters shall be deemed to be a part of the "Financing" and deemed to be the "Debt Letters" for all purposes of this Agreement. Parent shall promptly deliver to the Company copies of any termination, amendment, modification, waiver or replacement of the Debt Letters.

(f) If funds in the amounts set forth in the Debt Letters, or any portion thereof, become unavailable, Parent shall, and shall cause its Affiliates, as promptly as practicable following the occurrence of such event to (i) notify the Company in writing thereof, (ii) obtain substitute financing sufficient to enable Parent to consummate the Merger and the other transactions contemplated hereby in accordance with its terms (the "**Substitute Financing**") and (iii) obtain a new financing commitment letter that provides for such Substitute Financing and, promptly after execution thereof, deliver to the Company true, complete and correct copies of the new commitment letter and the related fee letters (in redacted form reasonably satisfactory to the Persons providing such Substitute Financing removing only the fee amounts, pricing caps, the rates and amounts included in the "market flex") and related definitive financing documents with respect to such Substitute Financing; provided, however, that any such Substitute Financing shall not, without the prior written consent of the Company, (1) reduce the aggregate amount of the Financing (including by increasing the amount of fees to be paid or original issue discount), (2) impose new or additional conditions to the Financing or otherwise expand or render more burdensome to Parent or its Affiliates any of the conditions to the Financing or (3) otherwise expand, amend, modify or waive any provision of the Debt Letters in a manner that in any such case would reasonably be expected to (A) delay or make less likely the funding of the Financing (or satisfaction of the conditions to the Financing) on the Closing Date, (B) adversely impact the ability of Parent or its Affiliates to enforce its rights against the Financing Parties or any other parties to the Debt Letters or the definitive agreements with respect thereto or (C) adversely affect the ability of Parent to timely consummate the Merger and the other transactions contemplated hereby. Upon obtaining any commitment for any such Substitute Financing, such financing shall be deemed to be a part of the "Financing" and any commitment letter for such Substitute Financing shall be deemed the "Debt Letters" for all purposes of this Agreement.

(g) Parent shall pay, or cause to be paid, as the same shall become due and payable, all fees and other amounts that become due and payable under the Debt Letters.

(h) Notwithstanding anything contained in this Agreement to the contrary, Parent and Merger Sub expressly acknowledge and agree that neither Parent's nor Merger Sub's obligations hereunder are conditioned in any manner upon Parent or Merger Sub obtaining the Financing, any Substitute Financing or any other financing.

SECTION 5.05 Financing Cooperation.

(a) From the date hereof until the Closing (or the earlier termination of this Agreement pursuant to Section 8.01), subject to the limitations set forth in this Section 5.05, and unless otherwise agreed by Parent, the Company will use its reasonable best efforts to cooperate with Parent and its Affiliates as reasonably requested by Parent in connection with Parent's arrangement of the Financing (which, solely for purposes of this Section 5.05, shall include any alternative equity or debt capital markets financings contemplated by the Debt Letters). Such cooperation will include using reasonable best efforts to:

(i) make appropriate officers reasonably available, with appropriate advance notice, for participation in bank meetings, due diligence sessions, meetings with ratings agencies and road shows, reasonable assistance in the preparation of confidential information memoranda, private placement memoranda, prospectuses, presentations and similar documents as may be reasonably requested by Parent or any Financing Party, in each case, with respect to information relating to the Company and its Subsidiaries in connection with customary marketing efforts of Parent and its Affiliates for all or any portion of the Financing;

(ii) furnish Parent and the Financing Parties with copies of such financial data with respect to the Company and its Subsidiaries which is prepared by the Company in the ordinary course of business or can be prepared by the Company without undue burden (with any cost thereof to be promptly reimbursed by Parent) as is reasonably requested by Parent or any Financing Party and is customarily required for the arrangement and syndication of financings similar to the Financing committed pursuant to the Debt Letters, including such information necessary to allow Parent to prepare pro forma financial statements in accordance with Article 11 of Regulation S-X under the Securities Act of 1933, as amended, and identify any such financial information as suitable for distribution to "public side" lenders;

(iii) request that the Company's independent accountants participate in drafting sessions and accounting due diligence sessions and cooperate with the Financing (including as set forth in the Debt Letters as in effect on the date of this Agreement) or in connection with a customary offering of securities, including the type described in the Commitment Letter, consistent with their customary practice, including requesting that they provide customary consents and comfort letters (including "negative assurance" comfort), including in respect of historical financial statements of the Company, to the extent required in connection with the marketing and syndication of Financing (including as set forth in the Debt Letters as in effect on the date of this Agreement) or as are customarily required in an underwritten offering of securities of the type described in the Debt Letters, or as may otherwise be required pursuant to applicable Law or the rules or regulations of any national securities exchange in connection with the Merger or any alternative financing therefor, and provide customary management letters in connection with the foregoing;

(iv) furnish to legal counsel of Parent and to legal counsel of any Financing Party such information as may be reasonably requested by such counsel in connection with any legal opinion that such counsel may be required to deliver in connection with such Financing; and

(v) furnish Parent and the Financing Parties, within five (5) Business Days following written request, such documentation and other information as any Financing Party may reasonably determine is required by regulatory authorities under applicable "know your customer" and anti-money laundering rules and regulations, including without limitation the PATRIOT Act.

provided, further, that nothing in this Agreement shall require the Company to cause the delivery of (1) legal opinions or reliance letters or any certificate as to solvency or any other certificate necessary for the Financing, other than as provided by Section 5.05(a)(iii), (2) any financial information for any period, including any audited financial information or any financial information prepared in accordance with Regulation S-K or Regulation S-X under the Securities Act of 1933, as amended, in any case in a form not customarily prepared by the Company with respect to such period, other than as provided by Section 5.05(a)(ii) or (3) any financial information with respect to a month or fiscal period that has not yet ended or has ended less than 40 days (or, in the case of a fiscal year, 60 days) prior to the date of such request.

(b) Notwithstanding anything to the contrary contained in this Agreement (including this Section 5.05): (i) nothing in this Agreement (including this Section 5.05) shall require any such cooperation to the extent that it would (1) require the Company to pay any commitment or other fees, reimburse any expenses or otherwise incur any liabilities or give any indemnities prior to the Closing,

(2) unreasonably interfere with the ongoing business or operations of the Company or the Company Subsidiaries, (3) require the Company or any of the Company Subsidiaries to enter into or approve any agreement or other documentation effective prior to the Closing or agree to any change or modification of any existing agreement or other documentation that would be effective prior to the Closing or (4) require the Company, any of the Company Subsidiaries or any of their respective boards of directors (or equivalent bodies) to approve or authorize the Financing, and (ii) no action, liability or obligation (including any obligation to pay any commitment or other fees or reimburse any expenses) of the Company, its Subsidiaries, or any of their respective Representatives under any certificate, agreement, arrangement, document or instrument relating to the Financing shall be effective until the Closing.

(c) Parent shall (i) promptly upon request by the Company, reimburse the Company for all of its fees and expenses (including fees and expenses of counsel and accountants) incurred by the Company, any of the Company Subsidiaries, any of its or their Representatives in connection with any cooperation contemplated by this Section 5.05 and (ii) indemnify and hold harmless the Company, the Company Subsidiaries and its and their Representatives against any claim, loss, damage, injury, liability, judgment, award, penalty, fine, Tax, cost (including cost of investigation), expense (including fees and expenses of counsel and accountants) or settlement payment incurred as a result of, or in connection with, such cooperation or the Financing and any information used in connection therewith.

ARTICLE VI

ADDITIONAL AGREEMENTS

SECTION 6.01 Preparation of the Proxy Statement; Company Shareholders Meeting.

(a) The Company shall use its reasonable best efforts to prepare and cause to be filed with the SEC no later than sixty (60) days following the date hereof, except to the extent of any delay caused by Parent, a proxy statement to be mailed to the shareholders of the Company relating to the Company Shareholders Meeting (together with any amendments or supplements thereto, the "**Proxy Statement**") in preliminary form. Each of Parent and Merger Sub shall furnish all information concerning itself and its Affiliates to the Company, and provide such other assistance, as may be reasonably requested by the Company or the Company's outside legal counsel in connection with the preparation, filing and distribution of the Proxy Statement.

(b) The Company agrees that (i) none of the information supplied or to be supplied by the Company for inclusion or incorporation by reference in the Proxy Statement will, at the date it is first mailed to the Company's shareholders or at the time of the Company Shareholders Meeting, contain any untrue statement of a material fact or omit to state any material fact required to be stated therein or necessary in order to make the statements therein, in the light of the circumstances under which they are made, not misleading and (ii) except with respect to any information supplied to the Company by Parent or Merger Sub for inclusion or incorporation by reference in the Proxy Statement, the Proxy Statement will comply as to form in all material respects with the requirements of the Exchange Act and the rules and regulations of the SEC promulgated thereunder. Parent and Merger Sub agree that none of the information supplied or to be supplied by Parent or Merger Sub for inclusion or incorporation by reference in the Proxy Statement will, at the date it is first mailed to the Company's shareholders or at the time of the Company Shareholders Meeting, contain any untrue statement of a material fact or omit to state any material fact required to be stated therein or necessary in order to make the statements therein, in the light of the circumstances under which they are made, not misleading.

(c) The Company shall promptly notify Parent after the receipt of any comments from the SEC with respect to, or any request from the SEC for amendments or supplements to, the Proxy

Statement and shall provide Parent with copies of all correspondence between it and its Affiliates and Representatives, on the one hand, and the SEC, on the other hand, and:

(i) each of the Company and Parent shall use its reasonable best efforts (1) to respond as promptly as reasonably practicable to any comment from the SEC with respect to, or any request from the SEC for amendments or supplements to, the Proxy Statement and (2) to have the SEC advise the Company as promptly as reasonably practicable that the SEC has no further comments on the Proxy Statement;

(ii) the Company shall file the Proxy Statement in definitive form with the SEC and cause such definitive Proxy Statement to be mailed to the shareholders of the Company as promptly as reasonably practicable after the SEC advises the Company that the SEC has no further comments on the Proxy Statement; and

(iii) unless the Company Board has made a Company Adverse Recommendation Change, the Company shall include the Company Board Recommendation in the preliminary and definitive Proxy Statements.

Notwithstanding anything to the contrary herein, prior to filing the Proxy Statement in preliminary form with the SEC, responding to any comment from the SEC with respect to, or any request from the SEC for amendments or supplements to, the Proxy Statement or mailing the Proxy Statement in definitive form to the shareholders of the Company, the Company shall provide Parent with an opportunity to review and comment on such document or response and consider in good faith any of Parent's comments thereon. Each Party shall use its reasonable best efforts to have the SEC advise the Company, as promptly as reasonably practicable after the filing of the preliminary Proxy Statement, that the SEC has no further comments on the Proxy Statement, and each of the Company and Parent shall also take any other action (except for qualifying to do business in any jurisdiction in which it is not now so qualified) required to be taken under the Securities Act, the Exchange Act, any applicable foreign or state securities or "blue sky" Laws and the rules and regulations thereunder in connection with the Merger.

(d) If, prior to the Effective Time, any event occurs with respect to Parent or any Affiliate of Parent, or any change occurs with respect to other information supplied by Parent for inclusion in the Proxy Statement, that is required to be described in an amendment of, or a supplement to, the Proxy Statement, Parent shall promptly notify the Company of such event, and Parent and the Company shall cooperate in the prompt filing with the SEC of any necessary amendment or supplement to the Proxy Statement so that either such document would not include any misstatement of a material fact or omit to state any material fact required to be stated therein or necessary in order to make the statements made therein, in the light of the circumstances under which they are made, not misleading, and, as required by Law, in disseminating the information contained in such amendment or supplement to the Company's shareholders. Nothing in this Section 6.01(d) shall limit the obligations of any Party under Section 6.01(a).

(e) If prior to the Effective Time, any event occurs with respect to the Company or any Company Subsidiary, or any change occurs with respect to other information supplied by the Company for inclusion in the Proxy Statement, that is required to be described in an amendment of, or a supplement to, the Proxy Statement, the Company shall promptly notify Parent of such event, and the Company and Parent shall cooperate in the prompt filing with the SEC of any necessary amendment or supplement to the Proxy Statement so that either such document would not include any misstatement of a material fact or omit to state any material fact required to be stated therein or necessary in order to make the statements made therein, in the light of the circumstances under which they are made, not misleading and, as required by Law, in disseminating the information contained in such amendment or supplement to the

Company's shareholders. Nothing in this Section 6.01(e) shall limit the obligations of any Party under Section 6.01(a).

(f) The Company shall, as soon as practicable after the mailing of the definitive Proxy Statement to the shareholders of the Company, duly call, give notice of, convene and hold the Company Shareholders Meeting. Unless the Company Board has made a Company Adverse Recommendation Change, the Company shall use its reasonable best efforts to solicit and secure the Company Shareholder Approval as soon as practicable, including postponing or adjourning the Company Shareholders Meeting to allow additional solicitation of votes if necessary to obtain the Company Shareholder Approval.

(g) Parent shall be responsible for 100% of the fees, costs and expenses (except for the fees, costs and expenses of the Company's advisors), including any filings fees, associated with the preparation, filing and mailing of the Proxy Statement.

SECTION 6.02 Access to Information; Confidentiality.

(a) Subject to applicable Law and the Confidentiality Agreement, the Company shall, and shall cause each of the Company Subsidiaries to, afford to Parent and its Representatives reasonable access (at Parent's sole cost and expense), during normal business hours and upon reasonable advance notice, during the period from the date of this Agreement until the earlier of the Effective Time or termination of this Agreement pursuant to Section 8.01, to the Company's material properties, books, contracts, commitments, personnel and records, and during such period, the Company shall, and shall cause the Company Subsidiaries to, make available promptly to Parent (i) to the extent not publicly available, a copy of each material Filing made by it during such period pursuant to the requirements of securities Laws or filed with or sent to the SEC, the FERC, the FCC, the State Commissions or any other Governmental Entity and (ii) all other material information concerning its business, properties and personnel as such Parent may reasonably request; provided, however, that the Company may withhold from Parent or its Representatives any document or information that the Company believes is subject to the terms of a confidentiality agreement with a third party (provided that the Company shall use its commercially reasonable efforts to obtain the required consent of such third party to disclose such document or information) or subject to any attorney–client privilege (provided that the Company shall use its commercially reasonable best efforts to allow the disclosure of such document or information (or as much of it as possible) in a manner that does not result in a loss of attorney–client privilege) or is competitively or commercially sensitive (as determined in the Company's reasonable discretion); provided, further, that Parent and its Representatives shall not have the right to collect any air, soil, surface water or ground water samples or perform any invasive or destructive air sampling on, under, at or from any of the properties owned, leased or operated by the Company or any Company Subsidiary. Except for incidents caused by the Company's or its Affiliate's intentional misconduct, Parent shall indemnify the Company and its Affiliates and Representatives from, and hold the Company and its Affiliates and Representatives harmless against, any and all Claims, losses, liabilities, damages, judgments, inquiries, fines and reasonable fees, costs, expenses, including attorneys' fees and disbursements, and the cost of enforcing this indemnity arising out of or resulting from any access provided pursuant to this Section 6.02(a).

(b) All documents and information exchanged pursuant to this Section 6.02 shall be subject to the confidentiality and standstill agreement, dated as of November 24, 2015, between the Company and Guarantor (the "**Confidentiality Agreement**"). If this Agreement is terminated pursuant to Section 8.01, the Confidentiality Agreement shall automatically be deemed to be amended and restated such that (i) Section 10 (Standstill) of the Confidentiality Agreement shall remain in effect for two (2) years after the date of such termination, as if the Parties had never entered into this Agreement, and

(ii) the other provisions of the Confidentiality Agreement shall remain in effect for two (2) years after such termination, as if the Parties had never entered into this Agreement.

SECTION 6.03 Further Actions; Regulatory Approvals; Required Actions.

(a) Subject to the terms and conditions of this Agreement, each of the Parties shall take, or cause to be taken, all actions, and do, or cause to be done, and assist and cooperate with the other Parties in doing, all things necessary to cause the conditions to the Closing set forth in Article VII to be satisfied as promptly as reasonably practicable or to effect the Closing as promptly as reasonably practicable, including (i) making all necessary Filings with Governmental Entities or third parties, (ii) obtaining the Required Consents and all other third-party Consents that are necessary, proper or advisable to consummate the Merger, (iii) obtaining the Required Statutory Approvals and all other Consents of Governmental Entities that are necessary, proper or advisable to consummate the Merger and (iv) executing and delivering any additional instruments that are necessary, proper or advisable to consummate the Merger. Parent shall be responsible for 100% of the fees, costs and expenses (except for the fees, costs and expenses of the Company's advisors), including any filing fees associated with any Filings or Consents contemplated by this Section 6.03.

(b) In connection with and without limiting the generality of Section 6.03(a), each of Parent and the Company shall:

(i) make or cause to be made, in consultation and cooperation with the other, (1) an appropriate filing of a Notification and Report Form pursuant to the HSR Act relating to the Merger, following the filing of all initial applications for, and at least six months prior to the reasonably expected date of receipt of, all Required Statutory Approvals, and (2) all draft and final filings required in connection with the CFIUS Approval in accordance with 31 C.F.R. Part 800 as promptly as practicable after the date of this Agreement;

(ii) as promptly as practicable after the date of this Agreement, make or cause to be made all necessary Filings to the FERC relating to the Merger;

(iii) as promptly as practicable after the date of this Agreement, make or cause to be made all necessary Filings with other Governmental Entities relating to the Merger, including any such Filings necessary to obtain any Required Statutory Approval;

(iv) furnish to the other all assistance, cooperation and information reasonably required for any such Filing and in order to achieve the effects set forth in this Section 6.03;

(v) unless prohibited by applicable Law or by a Governmental Entity, give the other reasonable prior notice of any such Filing and, to the extent reasonably practicable, of any communication with any Governmental Entity relating to the Merger (including with respect to any of the actions referred to in this Section 6.03(b)) and, to the extent reasonably practicable, permit the other to review and discuss in advance, and consider in good faith the views of, and secure the participation of, the other in connection with any such Filing or communication;

(vi) respond as promptly as practicable under the circumstances to any inquiries received from any Governmental Entity or any other authority enforcing applicable Antitrust Laws for additional information or documentation in connection with antitrust, competition or similar matters (including a "second request" under the HSR Act) and not extend any waiting period under the HSR Act or enter into any agreement with any such Governmental Entity or other authorities not to consummate the Merger, except with the prior written consent of the other Party;

(vii) provide any information requested by CFIUS or any other agency or branch of the U.S. government in connection with the CFIUS review or investigation of the transactions contemplated by this Agreement; and

(viii) unless prohibited by applicable Law or a Governmental Entity, to the extent commercially reasonably practicable, (1) not participate in or attend any formal meeting with any Governmental Entity in respect of the Merger without the other Party, (2) keep the other Party apprised with respect to any meeting or substantive conversation with any Governmental Entity in respect of the Merger, (3) cooperate in the filing of any substantive memoranda, white papers, filings, correspondence or other written communications explaining or defending this Agreement or the Merger, articulating any regulatory or competitive argument or responding to requests or objections made by any Governmental Entity and (4) furnish the other Party with copies of all substantive correspondence, Filings and communications (and memoranda setting forth the substance thereof) between it and its Affiliates and their respective Representatives on the one hand, and any Governmental Entity or members of any Governmental Entity's staff, on the other hand, with respect to this Agreement or the Merger; provided that the Parties shall be permitted to redact any correspondence, Filing or communication to the extent such correspondence, Filing or communication contains commercially sensitive information.

(c) Parent shall not, and shall cause its Affiliates not to, take any action, including acquiring any asset, property, business or Person (by way of merger, consolidation, share exchange, investment, other business combination, asset, stock or equity purchase, or otherwise), that could reasonably be expected to adversely affect obtaining or making any Consent or Filing contemplated by this Section 6.03 or the timely receipt thereof. In furtherance of and without limiting any of Parent's covenants and agreements under this Section 6.03, Parent shall use its reasonable best efforts to avoid or eliminate each and every impediment that may be asserted by a Governmental Entity pursuant to any Antitrust Law with respect to the Merger or in connection with granting any Required Statutory Approval so as to enable the Closing to occur as soon as reasonably possible; provided, however, that notwithstanding the foregoing or any other provision of this Agreement, Parent and its Affiliates shall not be obligated to, and Company shall not and shall cause the Company Subsidiaries not to, take any action or to agree or consent to or accept any terms, conditions, liabilities, obligations, commitments, sanctions or undertakings in connection with any Required Statutory Approval that, individually or in the aggregate, would be reasonably likely to have a material adverse effect on the business, properties, financial condition or results of operations of Liberty Utilities and its Subsidiaries (including for such purpose, the Company and its Subsidiaries), taken as a whole (a "**Burdensome Effect**"). Subject to the foregoing limitation, such reasonable best efforts shall include the following:

(i) defending through litigation on the merits, including appeals, any Claim asserted in any court or other proceeding by any Person, including any Governmental Entity, that seeks to or could prevent or prohibit or impede, interfere with or delay the consummation of the Closing;

(ii) proposing, negotiating, committing to and effecting, by consent decree, hold separate order or otherwise, the sale, divestiture, licensing or disposition of any assets or businesses of Parent or its Affiliates or the Company or the Company Subsidiaries, including entering into customary ancillary agreements on commercially reasonable terms relating to any such sale, divestiture, licensing or disposition;

(iii) agreeing to any limitation on the conduct of Parent or its Affiliates (including, after the Closing, the Surviving Corporation and the Company Subsidiaries);

(iv) not withdrawing and/or refiling any HSR Act submission, extending any waiting period or entering into any agreement or understanding with any Governmental Entity without consulting and obtaining written consent from the Company; and

(v) agreeing to take any other action as may be required by a Governmental Entity in order to effect each of the following: (1) obtaining all Required Statutory Approvals as soon as reasonably possible and in any event before the End Date, (2) avoiding the entry of, or having vacated, lifted, dissolved, reversed or overturned any Judgment, whether temporary, preliminary or permanent, that is in effect that prohibits, prevents or restricts consummation of, or impedes, interferes with or delays, the Closing and (3) effecting the expiration or termination of any waiting period, which would otherwise have the effect of preventing, prohibiting or restricting consummation of the Closing or impeding, interfering with or delaying the Closing.

(d) Parent shall promptly notify the Company and the Company shall notify Parent of any notice or other communication from any Person alleging that such Person's Consent is or may be required in connection with the Merger.

SECTION 6.04 Transaction Litigation. The Company shall promptly notify Parent of any shareholder litigation arising from this Agreement or the Merger that is brought against the Company or members of the Company Board ("**Transaction Litigation**"). The Company shall reasonably consult with Parent with respect to the defense or settlement of any Transaction Litigation and shall not settle any Transaction Litigation without Parent's consent (not to be unreasonably withheld, conditioned or delayed).

SECTION 6.05 Section 16 Matters. Prior to the Effective Time, the Company shall take all such steps as may be required to cause any dispositions of Company Common Stock (including derivative securities with respect to Company Common Stock) directly resulting from the Merger by each individual who will be subject to the reporting requirements of Section 16(a) of the Exchange Act with respect to the Company immediately prior to the Effective Time to be exempt under Rule 16b-3 promulgated under the Exchange Act.

SECTION 6.06 Governance Matters.

(a) Parent shall cause the Surviving Corporation and its Utility Subsidiaries to maintain their combined headquarters in the location of such headquarters as of immediately prior to the Closing.

(b) Upon the Effective Time, the Joplin headquarters of the Company shall become the headquarters of Parent and, following the Effective Time, Parent will cause to be transitioned to Parent management responsibilities for the distribution utility operations of Parent's Affiliates in the surrounding geographic region (including Arkansas, Iowa, Illinois, Kansas, Missouri, Oklahoma and Texas), to establish the Joplin headquarters as a regional leadership hub in the broader organization of Parent and its utility Affiliates.

(c) Upon the Effective Time, Parent will take all necessary action (i) to cause to be appointed to the board of directors of Parent the current members of the Company's board of directors, and (ii) to cause the Chief Executive Officer of the Company to be appointed as the chief executive officer of Parent, with customary responsibility for the selection of the senior leadership team of Parent and its utility Subsidiaries.

(d) Following the Effective Time, Parent will cause the governance and nominating committee of the board of directors of Guarantor to consider current members of the Company's board of directors as candidates to fill vacancies on Guarantor's board of directors, including vacancies resulting from an expected expansion of Guarantor's board of directors.

(e) Parent shall cause the Surviving Corporation and the Company Subsidiaries to maintain and operate their respective businesses under the "Empire District" brand for a period of at least five (5) years following the Effective Time, provided that such use may also include "a Liberty Utilities company" or similar co-branding designation.

(f) From and after the Effective Time, Parent shall cause the Surviving Corporation and the Company Subsidiaries to maintain historic levels of community involvement and charitable contributions and support in the existing service territories of the Company and the Company Subsidiaries, including as set forth on Section 6.06(f) of the Company Disclosure Letter.

SECTION 6.07 Public Announcements. Except with respect to (a) a Company Adverse Recommendation Change or as otherwise permitted by Section 5.03(e), (b) any dispute between or among the Parties regarding this Agreement or the transactions contemplated hereby, and (c) a press release or other public statement that is consistent in all material respects with previous press releases, public disclosures or public statements made by a Party in accordance with this Agreement, including in investor conference calls, SEC Filings, Q&As or other publicly disclosed documents, in each case under this clause (c), to the extent such disclosure is still accurate, Parent and the Company shall consult with each other before issuing, and give each other the opportunity to review and comment upon, any press release or other written public statement with respect to this Agreement or the Merger and shall not (and shall cause its respective Affiliates not to) issue any such press release or make any such written public statement prior to such consultation, except as such Party reasonably concludes may be required by applicable Law, court process or by obligations pursuant to any listing agreement with any national securities exchange or national securities quotation system. The Company and Parent agree that the initial press release to be issued with respect to this Agreement or Merger shall be in the form agreed to by the Parties prior to the date hereof. Nothing in this Section 6.07 shall limit the ability of any Party to make internal announcements to its respective employees that are consistent in all material respects with the prior public disclosures regarding the transactions contemplated by this Agreement.

SECTION 6.08 Fees, Costs and Expenses. Except as provided otherwise in this Agreement, including Section 5.05(c), Section 6.01(g), Section 6.03(a), Section 9.15 and Article VIII, all fees, costs and expenses incurred in connection with this Agreement and the transactions contemplated hereby shall be paid by the Party incurring such fees, costs or expenses, whether or not the Closing occurs.

SECTION 6.09 Indemnification, Exculpation and Insurance.

(a) Parent agrees that all rights to indemnification, advancement of expenses and exculpation from liabilities for acts or omissions occurring at or prior to the Effective Time now existing in favor of the current or former directors, officers or employees of the Company and the Company Subsidiaries as provided in their respective Organization Documents and any indemnification or other similar Contracts of the Company or any Company Subsidiary, in each case, as in effect on the date of this Agreement, shall continue in full force and effect in accordance with their terms (it being agreed that after the Closing such rights shall be mandatory rather than permissive, if applicable), and Parent shall cause the Surviving Corporation and the Company Subsidiaries to perform their respective obligations thereunder. Without limiting the foregoing, from and after the Effective Time, the Surviving Corporation agrees that it will indemnify and hold harmless each individual who is as of the date of this Agreement, or who becomes prior to the Effective Time, a director, officer or employee of the Company or any Company Subsidiary or who is as of the date of this Agreement, or who thereafter commences prior to the Effective Time, serving at the request of the Company or any Company Subsidiary as a director, officer or employee of another Person (the "**Company Indemnified Parties**"), against all claims, losses, liabilities, damages, judgments, inquiries, fines and reasonable fees, costs and expenses, including attorneys' fees and disbursements, incurred in connection with any Claim, whether civil, criminal, administrative or investigative (including with respect to matters existing or occurring at or prior to the Effective Time (including this Agreement and the transactions and actions contemplated hereby)), arising out of or pertaining to the fact that the Company Indemnified Party is or was a director, officer or employee of the Company or any Company Subsidiary or is or was serving at the request of the Company or any Company Subsidiary as a director, officer or employee of another Person, whether asserted or claimed prior to, at or after the Effective Time, to the fullest extent permitted under applicable Law. In the event of any such Claim, (i) each Company Indemnified Party will be entitled to advancement of expenses incurred in the defense of any such Claim from Parent within ten (10) Business Days after receipt by Parent from the Company Indemnified Party of a request therefor; provided that any Person to whom expenses are advanced provides an undertaking, if and only to the extent required by applicable Law or the Surviving Corporation's Organizational Documents, to repay such advances if it is ultimately determined by final adjudication that such person is not entitled to indemnification and (ii) the Surviving Corporation shall cooperate in good faith in the defense of any such matter.

(b) In the event that Parent or the Surviving Corporation or any of its successors or assigns (i) consolidates with or merges into any other Person and is not the continuing or surviving corporation or entity of such consolidation or merger or (ii) transfers or conveys all or substantially all of its properties and assets to any Person, then, and in each such case, Parent or the Surviving Corporation, as the case may be, shall cause proper provision to be made so that the successors and assigns of Parent or the Surviving Corporation, as the case may be, assume the covenants and agreements set forth in this Section 6.09.

(c) For a period of six (6) years from and after the Effective Time, the Surviving Corporation shall either cause to be maintained in effect the current policies of directors' and officers' liability insurance and fiduciary liability insurance maintained by the Company or its Subsidiaries or provide substitute policies for the Company and its current and former directors and officers who are currently covered by the directors' and officers' and fiduciary liability insurance coverage currently maintained by the Company, in either case, of not less than the existing coverage and having other terms not less favorable to the insured persons than the directors' and officers' liability insurance and fiduciary liability insurance coverage currently maintained by the Company with respect to claims arising from facts or events that occurred on or before the Effective Time (with insurance carriers having at least an "A" rating by A.M. Best with respect to directors' and officers' liability insurance and fiduciary liability insurance), except that in no event shall the Surviving Corporation be required to pay with respect to such insurance policies in respect of any one policy year more than 300% of the aggregate annual premium most recently paid by the Company prior to the date of this Agreement (the "**Maximum Amount**"), and if the Surviving Corporation is unable to obtain the insurance required by this Section 6.09(c) it shall obtain as much comparable insurance as possible for the years within such six (6) year period for an annual premium equal to the Maximum Amount, in respect of each policy year within such period. In lieu of such insurance, prior to the Closing Date the Company may, at its option but following consultation with Parent, purchase a "tail" directors' and officers' liability insurance policy and fiduciary liability insurance policy for the Company and its current and former directors, officers and employees who are currently covered by the directors' and officers' and fiduciary liability insurance coverage currently maintained by the Company, such tail to provide coverage in an amount not less than the existing coverage and to have other terms substantially comparable (and not less favorable) to the insured persons than the directors' and officers' liability insurance and fiduciary liability insurance coverage currently maintained by the Company with respect to claims arising from facts or events that occurred on or before the Effective Time for a period of not less than six (6) years; provided that in no event shall the cost of any such tail policy in respect of any one policy year exceed the Maximum Amount. The Surviving Corporation shall maintain such policies in full force and effect, and continue to honor the obligations thereunder.

(d) The provisions of this Section 6.09 (i) shall survive consummation of the Merger, (ii) are intended to be for the benefit of, and will be enforceable by, each indemnified or insured party (including the Company Indemnified Parties), his or her heirs and his or her representatives and (iii) are in addition to, and not in substitution for, any other rights to indemnification or contribution that any such Person may have by contract or otherwise.

(e) From and after the Effective Time, Parent shall guarantee the prompt payment of the obligations of the Surviving Corporation and the Company Subsidiaries under this Section 6.09.

SECTION 6.10 Employee Matters.

(a) During the period commencing at the Effective Time and ending on the two (2) year anniversary of the Effective Time (the "**Continuation Period**"), Parent shall, and shall cause the Surviving Corporation to, provide each individual who is employed by the Company or a Company Subsidiary immediately prior to the Effective Time and who remains employed thereafter by the Surviving Corporation, Parent or any of their Affiliates (each, a "**Company Employee**") who is not covered by a Company Union Contract and who remains a Company Employee with (i) a base salary or wage rate that is no less favorable than that provided to the Company Employee immediately prior to the Effective Time, (ii) aggregate incentive compensation opportunities that are substantially comparable, in the aggregate, to those provided to the Company Employee immediately prior to the Effective Time and (iii) employee benefits that are substantially comparable, in the aggregate, to those provided to the Company Employee immediately prior to the Effective Time. During the three-year period following the Continuation Period, Parent shall, or shall cause the Surviving Corporation or its other Affiliates to, treat Company Employees with respect to the payment of base salary or wage rate, incentive compensation opportunities, employee benefits and severance benefits no less favorably in the aggregate than similarly situated employees of the Parent and its Affiliates. Prior to the third anniversary of the Closing Date, Parent shall not, and shall cause the Surviving Corporation to not, terminate or amend in any manner that is materially adverse to the participants therein, any of the Company Benefit Plans listed on Section 6.10(a) of the Company Disclosure Letter. During the three-year period following the third anniversary of the Closing Date, subject to Section 6.10(d)(ii), Parent shall, or shall cause the Surviving Corporation to, treat retirees of the Company and its Subsidiaries with respect to the provision of post-retirement welfare benefits no less favorably than similarly situated retirees of the Parent and its Affiliates. As soon as practicable following the end of the fiscal year in which the Effective Time occurs, Parent shall, or shall cause the Surviving Corporation or its other Affiliates to, pay each Company Employee who remains employed with the Surviving Corporation, Parent or any of their Affiliates through the applicable payment date an annual cash bonus for such fiscal year in an amount determined based on the level of attainment of the applicable performance criteria under the bonus plan in which such Company Employee participated as of immediately prior to the Effective Time.

(b) With respect to each Company Employee who is covered by a Company Union Contract, Parent shall, and shall cause the Surviving Corporation to, continue to honor the Company Union Contracts, in each case as in effect at the Effective Time, in accordance with their terms (it being understood that this sentence shall not be construed to limit the ability of Parent or the Surviving Corporation to amend or terminate any such Company Union Contract, to the extent permitted by the terms of the applicable Company Union Contract and applicable Law). The provisions of this Section 6.10 shall be subject to any applicable provisions of the Company Union Contracts and applicable Law in respect of such Company Employee, to the extent the provisions of this Section 6.10 are inconsistent with or otherwise in conflict with the provisions of any such Company Union Contract or applicable Law.

(c) At the Effective Time, Parent shall, or shall cause the Surviving Corporation to, assume and honor in accordance with their terms all of the Company's and all of the Company Subsidiaries' employment, severance, retention, termination and change-in-control plans, policies, programs, agreements and arrangements (including any change-in-control severance agreement or other arrangement between the Company and any Company Employee) maintained by the Company or any Company Subsidiary, in each case, as in effect at the Effective Time, including with respect to any payments, benefits or rights arising as a result of the Merger (either alone or in combination with any other event), it being understood that this sentence shall not be construed to limit the ability of Parent or the Surviving Corporation to amend or terminate any such plans, policies, programs, agreements, or arrangements, to the extent permitted by the terms of the applicable plan, policy, program, agreement or arrangement. For purposes of any Company Benefit Plan or Company Benefit Agreement containing a definition of "change in control," "change of control" or similar term that relates to a transaction at the level of the Company, the Closing shall be deemed to constitute a "change in control," "change of control" or such similar term.

(d) With respect to all employee benefit plans of Parent, the Surviving Corporation or any of their Affiliates, including any "employee benefit plan" (as defined in Section 3(3) of ERISA) (including any vacation, paid time-off and severance plans), each Company Employee's service with the Company or any Company Subsidiary (as well as service with any predecessor employer of the Company or any such Company Subsidiary, to the extent service with the predecessor employer was recognized by the Company or such Company Subsidiary and is accurately reflected within a Company Employee's records) shall be treated as service with Parent, the Surviving Corporation or any of their Affiliates for all purposes, including determining eligibility to participate, level of benefits, vesting and benefit accruals, except (i) to the extent that such service was not recognized under the corresponding Company Benefit Plan immediately prior to the Effective Time, (ii) for purposes of any defined benefit retirement plan, any retiree welfare benefit plan, any grandfathered or frozen plan or any plan under which similarly situated employees of Parent and its Affiliates do not receive credit for prior service or (iii) to the extent that such recognition would result in any duplication of benefits for the same period of service.

(e) Parent shall, and shall cause the Surviving Corporation to, use commercially reasonable efforts to waive, or cause to be waived, any pre-existing condition limitations, exclusions, actively at work requirements and waiting periods under any welfare benefit plan maintained by Parent, the Surviving Corporation or any of their Affiliates in which Company Employees (and their eligible dependents) will be eligible to participate from and after the Effective Time, except to the extent that such pre-existing condition limitations, exclusions, actively-at-work requirements and waiting periods would not have been satisfied or waived under the corresponding Company Benefit Plan immediately prior to the Effective Time. Parent shall, or shall cause the Surviving Corporation to, use commercially reasonable efforts to recognize the dollar amount of all co-payments, deductibles and similar expenses incurred by each Company Employee (and his or her eligible dependents) during the calendar year in which the Effective Time occurs for purposes of satisfying such year's deductible and co-payment limitations under the relevant welfare benefit plans in which they will be eligible to participate from and after the Effective Time.

(f) Notwithstanding anything to the contrary herein, the provisions of this Section 6.10 are solely for the benefit of the parties to this Agreement, and no provision of this Section 6.10 is intended to, or shall, constitute the establishment or adoption of or an amendment to any employee benefit plan for purposes of ERISA or otherwise and no Company Personnel or any other individual associated therewith shall be regarded for any purpose as a third-party beneficiary of this Agreement or have the right to enforce the provisions hereof including in respect of continued employment (or resumed employment). Nothing contained herein shall alter the at-will employment relationship of any Company Employee.

SECTION 6.11 Merger Sub.

(a) Prior to the Effective Time, Merger Sub shall not engage in any activity of any nature except for activities related to or in furtherance of the Merger.

(b) Parent hereby (i) guarantees the due, prompt and faithful payment performance and discharge by Merger Sub of, and compliance by Merger Sub with, all of the covenants and agreements of Merger Sub under this Agreement and (ii) agrees to take all actions necessary, proper or advisable to ensure such payment, performance and discharge by Merger Sub hereunder.

SECTION 6.12 Takeover Statutes. If any Takeover Statute or similar statute or regulation becomes applicable to this Agreement or the Merger, the Company and the Company Board shall grant such approvals and take such actions as are reasonably appropriate to ensure that the Merger may be consummated as promptly as practicable on the terms contemplated by this Agreement.

SECTION 6.13 Stock Exchange De-Listing. Prior to the Closing Date, the Company shall cooperate with Parent and use reasonable best efforts to take, or cause to be taken, all actions, and do or cause to be done all things, reasonably necessary, proper or advisable on its part under applicable Laws and rules and policies of the NYSE to enable the delisting by the Surviving Corporation of the Company Common Stock from the NYSE and the deregistration of the Company Common Stock under the Exchange Act as promptly as practicable after the Effective Time.

SECTION 6.14 Resolution of Impediments.

(a) In the event that, prior to the End Date, any Required Statutory Approval has been denied or has been obtained but has or would be reasonably likely to have a Burdensome Effect, or any Legal Restraint has been imposed with respect to any Required Statutory Approval (each, a "**Failed Condition**"), then the Parties shall promptly confer in good faith regarding and, from the date of such occurrence until the earlier of the End Date or the date that is sixty (60) days following such occurrence, shall use reasonable best efforts to promptly agree upon a strategy to cause the conditions specified in Section 7.01 to be satisfied, which may include appropriate changes to this Agreement or to the transactions contemplated hereby; provided, however, that no Party shall in any circumstances be obligated to alter or change the amount or form of the Merger Consideration. Following written agreement, if any, of the Parties with respect to changes to this Agreement or to the transactions contemplated hereby to address a Failed Condition, the Parties shall use their reasonable best efforts to promptly give effect to and implement such agreement, cause the conditions specified in Section 7.01 to be satisfied, and effect the Closing as promptly as reasonably practicable. Notwithstanding any other provision of this Agreement, no Party shall have the right to terminate this Agreement on the basis of a Failed Condition (i) during the period specified in the first sentence of this Section 6.14(a), or (ii) if such Party has failed to comply with its obligations under this Section 6.14(a), or (iii) following written agreement, if any, of the Parties with respect to changes to this Agreement or to the transactions contemplated hereby to address such Failed Condition, except as expressly provided in such written agreement.

(b) In the event that Parent determines in good faith that any Required Statutory Approval that is required as a result of any business or assets of the Company and its Subsidiaries that generated less than ten percent (10%) of the consolidated revenues of the Company in its most recent fiscal year is not reasonably likely to be obtained prior to the End Date (as extended pursuant to any other provision of this Agreement), or if obtained is reasonably likely to impose conditions or requirements that are materially burdensome in relation to the financial contributions of such business or assets, then upon the written request of Parent the Company shall, and shall cause the Company Subsidiaries to, reasonably cooperate with Parent to structure and pursue a disposition (whether by liquidation, dissolution, merger, consolidation, equity sale, asset sale, reorganization, recapitalization or otherwise) of such business or assets, to be effected only upon or following the Closing. Parent shall use its reasonable efforts to structure and arrange for such a disposition as promptly as reasonably practicable.

ARTICLE VII

CONDITIONS PRECEDENT

SECTION 7.01 Conditions to Each Party's Obligation to Effect the Transactions. The obligation of each Party to effect the Closing is subject to the satisfaction or waiver (by such Party) at or prior to the Closing of the following conditions:

(a) Company Shareholder Approval. The Company Shareholder Approval shall have been obtained.

(b) Required Statutory Approvals. The Required Statutory Approvals, including the expiration or termination of any waiting period applicable to the Merger under the HSR Act, shall have been obtained at or prior to the Effective Time, such approvals shall have become Final Orders and, unless waived by Parent, such approvals shall not, individually or in the aggregate, have or be reasonably likely to have a Burdensome Effect. For purposes of this Section 7.01(b), a "**Final Order**" means a Judgment by the relevant Governmental Entity that (1) has not been reversed, stayed, enjoined, set aside, annulled or suspended and is in full force and effect, (2) with respect to which, if applicable, any mandatory waiting period prescribed by Law before the Merger may be consummated has expired and (3) as to which all conditions to the consummation of the Merger prescribed by Law have been satisfied.

(c) No Legal Restraints. No Law and no Judgment, whether preliminary, temporary or permanent, shall be in effect that prevents, makes illegal or prohibits the consummation of the Merger (any such Law or Judgment, a "**Legal Restraint**").

SECTION 7.02 Conditions to Obligations of the Company. The obligation of the Company to effect Closing is further subject to the satisfaction or waiver (by the Company) at or prior to the Closing of the following conditions:

(a) Representations and Warranties. The representations and warranties of Parent and Merger Sub contained herein shall be true and correct (without giving effect to any limitation as to "materiality" or "Parent Material Adverse Effect" set forth therein) at and as of the Effective Time as if made at and as of such time (except to the extent expressly made as of an earlier date, in which case as of such earlier date), except where the failure of any such representation or warranty to be true and correct (without giving effect to any limitation as to "materiality" or "Parent Material Adverse Effect" set forth therein), individually or in the aggregate, has not had and would not reasonably be expected to have a Parent Material Adverse Effect.

(b) Performance of Covenants and Agreements of Parent and Merger Sub. Parent and Merger Sub shall have performed in all material respects all material covenants and agreements required to be performed by them under this Agreement at or prior to the Closing.

(c) Officer's Certificate. The Company shall have received a certificate signed on behalf of Parent by an executive officer of Parent certifying the satisfaction by Parent and Merger Sub of the conditions set forth in Section 7.02(a) and Section 7.02(b).

SECTION 7.03 Conditions to Obligations of Parent and Merger Sub. The obligations of Parent and Merger Sub to consummate the Merger is further subject to the satisfaction or waiver (by Parent and Merger Sub) at or prior to the Closing of the following conditions:

(a) Representations and Warranties. (i) The representations and warranties of the Company contained herein (except for the representations and warranties contained in Section 3.03) shall be true and correct (without giving effect to any limitation as to "materiality" or "Company Material Adverse Effect" set forth therein) at and as of the Effective Time as if made at and as of such time (except to the extent expressly made as of an earlier date, in which case as of such earlier date), except where the failure of any such representation or warranty to be true and correct (without giving effect to any limitation as to "materiality" or "Company Material Adverse Effect" set forth therein), individually or in the aggregate, has not had and would not reasonably be expected to have a Company Material Adverse Effect, and (ii) the representations and warranties of the Company contained in Section 3.03 shall be true and correct at and as of the Closing Date as if made at and as of such time (except to the extent expressly made as of an earlier date, in which case as of such earlier date), except where the failure of any such representation or warranty to be true and correct would be de minimis.

(b) Performance of Covenants and Agreements of the Company. The Company shall have performed in all material respects all material covenants and agreements required to be performed by it under this Agreement at or prior to the Closing.

(c) Absence of Company Material Adverse Effect. Since the date of this Agreement, no fact, circumstance, effect, change, event or development that, individually or in the aggregate, has had or would reasonably be expected to have Company Material Adverse Effect shall have occurred and be continuing.

(d) Officer's Certificate. Parent shall have received a certificate signed on behalf of the Company by an executive officer of the Company certifying the satisfaction by the Company of the conditions set forth in Section 7.03(a), Section 7.03(b) and Section 7.03(c).

ARTICLE VIII

TERMINATION, AMENDMENT AND WAIVER

SECTION 8.01 Termination Rights.

(a) Termination by Mutual Consent. The Company and Parent shall have the right to terminate this Agreement at any time prior to the Effective Time, whether before or after receipt of the Company Shareholder Approval, by mutual written consent.

(b) Termination by Either the Company or Parent. Each of the Company and Parent shall have the right to terminate this Agreement, at any time prior to the Effective Time, whether before or after the receipt of the Company Shareholder Approval, if:

(i) the Closing shall not have occurred by 5:00 p.m. New York City time on February 9, 2017 (the "**End Date**"); provided that if, prior to the End Date, all of the conditions to the Closing set forth in Article VII except for any condition set forth in Section 7.01(b) or Section 7.01(c) have been satisfied or waived, as applicable, or shall then be capable of being satisfied, the End Date automatically shall be extended to a date that is six (6) months after the End Date and, if so extended, such later date shall be the End Date; provided, further, that neither the Company nor Parent may terminate this Agreement if it (or, in the case of Parent, Merger Sub) is in breach of any of its covenants or agreements and such breach has caused or resulted in either (1) the failure to satisfy the conditions to the obligations of the terminating Party to consummate the Merger set forth in Article VII prior to the End Date or (2) the failure of the Closing to have occurred prior to the End Date;

(ii) the condition set forth in Section 7.01(c) is not satisfied and the Legal Restraint giving rise to such nonsatisfaction is permanent (rather than preliminary or temporary) and has become final and nonappealable; provided, however, that the right to terminate this Agreement under this Section 8.01(b)(ii) shall not be available to any Party whose failure to comply with any provision of this Agreement has been the cause of, or materially contributed to, either the imposition of such Legal Restraint or the failure of such Legal Restraint to be resisted, resolved, lifted or vacated, as applicable; or

(iii) the Company Shareholder Approval is not obtained at the Company Shareholders Meeting duly convened (unless such Company Shareholders Meeting has been adjourned, in which case at the final adjournment thereof).

(c) Termination by the Company. The Company shall have the right to terminate this Agreement:

(i) in the event that the Company Board has made a Company Adverse Recommendation Change on the basis of a Superior Company Proposal or a Company Intervening Event, so long as (1) the Company has complied in all material respects with its obligations under Section 5.03(c) and (2) the Company prior to or concurrently with such termination (A) solely in the case of a termination due to a Company Adverse Recommendation Change on the basis of a Superior Company Proposal, enters into a Company Acquisition Agreement with respect to such Superior Company Proposal and (B) pays to Parent the Company Termination Fee in accordance with Section 8.02(b)(ii); provided, however, that the Company shall not have the right to terminate this Agreement under this Section 8.01(c)(i) after the Company Shareholder Approval is obtained at the Company Shareholders Meeting;

(ii) if Parent or Merger Sub breaches or fails to perform any of its covenants or agreements contained herein, or if any of the representations or warranties of Parent or Merger Sub contained herein fails to be true and correct, which breach or failure (1) would give rise to the failure of a condition set forth in Section 7.01, Section 7.02(a) or Section 7.02(b), as applicable, and (2) is not reasonably capable of being cured by Parent or Merger Sub by the End Date (as it may be extended pursuant to this Agreement) or is not cured by Parent within thirty (30) days after receiving written notice from the Company of such breach or failure; provided, however, that the Company shall not have the right to terminate this Agreement under this Section 8.01(c)(ii) if the Company is then in breach of any covenant or agreement contained herein or any representation or warranty of the Company contained herein then fails to be true and correct such that the conditions set forth in Section 7.03(a) or Section 7.03(b), as applicable, could not then be satisfied; or

(iii) if (1) all of the conditions set forth in Section 7.01, Section 7.02 and Section 7.03 have been satisfied or waived in accordance with this Agreement as of the date that the Closing should have been consummated pursuant to Section 1.03 (except for those conditions that by their terms are to be satisfied at the Closing), (2) Parent and Merger Sub do not complete the Closing on the day that the Closing should have been consummated pursuant to Section 1.03, (3) a Financing Failure has occurred and (4) Parent and Merger Sub fail to consummate the Closing within five (5) Business Days following their receipt of written notice from the Company requesting such consummation.

(d) Termination by Parent. Parent shall have the right to terminate this Agreement:

(i) in the event that the Company Board or a committee thereof has made a Company Adverse Recommendation Change; provided, however, that Parent shall not have the right to terminate this Agreement under this Section 8.01(d) after the Company Shareholder Approval is obtained at the Company Shareholders Meeting; or

(ii) if the Company breaches or fails to perform any of its covenants or agreements contained herein, or if any of the representations or warranties of the Company contained herein fails to be true and correct, which breach or failure (1) would give rise to the failure of a condition set forth in Section 7.01, Section 7.03(a) or Section 7.03(b), as applicable, and (2) is not reasonably capable of being cured by the Company by the End Date (as it may be extended pursuant to this Agreement) or is not cured by the Company within thirty (30) days after receiving written notice from Parent of such breach or failure; provided, however, that Parent shall not have the right to terminate this Agreement under this Section 8.01(d)(ii) if Parent is then in breach of any covenant or agreement contained herein or any representation or warranty of Parent contained herein then fails to be true and correct such that the conditions set forth in Section 7.02(a) or Section 7.02(b), as applicable, could not then be satisfied.

SECTION 8.02 Effect of Termination; Termination Fees.

(a) In the event of termination of this Agreement by either Parent or the Company as provided in Section 8.01, this Agreement shall forthwith become void and have no effect, without any liability or obligation on the part of the Company or Parent (or any shareholder, Affiliate or Representative thereof), whether arising before or after such termination, based on, arising out of or relating to this Agreement or the negotiation, execution, performance or subject matter hereof (whether in contract or in tort or otherwise, or whether at law (including at common law or by statute) or in equity), except for (i) Section 5.05(c), Section 6.01(g), the last sentence of Section 6.02(a), the last sentence of Section 6.02(b), the last sentence of Section 6.03(a), Section 6.08, this Section 8.02 and Article IX, which provisions shall survive such termination and (ii) subject to Section 8.02(d), liability of any Party (whether or not the terminating Party) for any Willful Breach of this Agreement prior to such termination but solely to the extent such liability arises out of a Willful Breach by such Party of any covenant or agreement set forth herein that gave rise to the failure of a condition set forth in Article VII. The liabilities described in the preceding sentence shall survive the termination of this Agreement.

(b) Termination Fees.

(i) If (1) (A) either Parent or the Company terminates this Agreement pursuant to Section 8.01(b)(i) and, at the time of such termination, any of the conditions set forth in Section 7.01(b) or, in connection with the Required Statutory Approvals, Section 7.01(c) shall have not been satisfied and such conditions, if waivable by Parent, shall not have been waived by Parent, (B) either Parent or the Company terminates this Agreement pursuant to Section 8.01(b)(ii) (if and only if, the applicable Legal Restraint giving rise to such termination arises in connection with the Required Statutory Approvals) or (C) the Company terminates this Agreement pursuant to Section 8.01(c)(ii) based on a failure by Parent to perform its covenants or agreements under

Section 6.03, and in each case of the foregoing clauses (A), (B) and (C), at the time of such termination, all other conditions to the Closing set forth in Section 7.01(a), Section 7.03(a), Section 7.03(b) and Section 7.03(c) shall have been satisfied or waived (except for (I) those conditions that by their nature are to be satisfied at the Closing but which conditions would be satisfied or would be capable of being satisfied if the Closing Date were the date of such termination or (II) those conditions that have not been satisfied as a result of a breach of this Agreement by Parent), or (2) the Company terminates this Agreement pursuant to Section 8.01(c)(iii), then Parent shall pay to the Company a fee of Sixty-Five Million United States Dollars ($65,000,000) in cash (the "**Parent Termination Fee**"). Parent shall pay the Parent Termination Fee to the Company (to an account designated in writing by the Company) no later than three (3) Business Days after the date of the applicable termination.

(ii) If the Company terminates this Agreement pursuant to Section 8.01(c)(i) or Parent terminates this Agreement pursuant to Section 8.01(d)(i), the Company shall pay to Parent a fee of Fifty-Three Million United States Dollars ($53,000,000) in cash (the "**Company Termination Fee**"). The Company shall pay the Company Termination Fee to Parent (to an account designated in writing by Parent) prior to or concurrently with such termination of this Agreement by the Company pursuant to Section 8.01(c)(i) or no later than three (3) Business Days after the date of such termination of this Agreement by Parent pursuant to Section 8.01(d)(i).

(iii) If (1) either (A) Parent or the Company terminates this Agreement pursuant to Section 8.01(b)(iii), prior to the Company Shareholders Meeting a Company Takeover Proposal shall have been publicly disclosed, and as of the Company Shareholders Meeting such Company Takeover Proposal shall not have been withdrawn, or (B) Parent or the Company terminates this Agreement pursuant to Section 8.01(b)(i), prior to such termination a Company Takeover Proposal shall have been publicly disclosed, and as of such termination the Company Shareholders Meeting shall not have been held and such Company Takeover Proposal shall not have been withdrawn, or (C) Parent terminates this Agreement pursuant to Section 8.01(d)(ii) (solely with respect to breach of or failure to perform a covenant), prior to such termination a Company Takeover Proposal shall have been publicly disclosed, and as of such termination such Company Takeover Proposal shall not have been withdrawn, and (2) within nine (9) months after the termination of this Agreement, the Company shall have entered into a definitive agreement with respect to, or consummated, a Company Takeover Proposal (whether or not the same Company Takeover Proposal referred to in clause (1)), then the Company shall pay the Company Termination Fee to Parent (to an account designated in writing by Parent) within two (2) Business Days after the earlier of the date the Company enters into such definitive agreement or consummates such Company Takeover Proposal. For purposes of clause (2) of this Section 8.02(b)(iii), the term "Company Takeover Proposal" shall have the meaning assigned to such term in Section 5.01, except that the applicable percentage in the definition of "Company Takeover Proposal" shall be "more than 50%" rather than "20% or more."

(c) The Parties acknowledge that the agreements contained in Section 8.02(b) are an integral part of the transactions contemplated by this Agreement, and that, without these agreements, the parties would not enter into this Agreement. If Parent (or the Guarantor pursuant to the Guarantee) fails to promptly pay an amount due pursuant to Section 8.02(b)(i), or the Company fails to promptly pay an amount due pursuant to Section 8.02(b)(ii) or Section 8.02(b)(iii), and, in order to obtain such payment, Parent, on the one hand, or the Company, on the other hand, commences a Claim that results in a Judgment against the Company for the amount set forth in Section 8.02(b)(ii) or Section 8.02(b)(iii), or any portion thereof, or a Judgment against Parent (or the Guarantor pursuant to the Guarantee) for the amount set forth in Section 8.02(b)(i), or any portion thereof, the Company shall pay to Parent, on the one hand, or Parent (or the Guarantor pursuant to the Guarantee) shall pay to the Company, on the other hand, its costs and expenses (including reasonable attorneys' fees and the fees and expenses of any expert or consultant engaged by the Company) in connection with such Claim, together with interest on the amount of such payment from the date such payment was required to be made until the date of payment at the "U.S. Prime Rate" as quoted by the Wall Street Journal in effect on the date such payment was required to be made. Any amount payable pursuant to Section 8.02(b) shall be paid by the applicable Party by wire transfer of same-day funds prior to or on the date such payment is required to be made under Section 8.02(b).

(d) Without limiting any rights of the Company under Section 9.10 prior to the termination of this Agreement pursuant to Section 8.01, if this Agreement is terminated under circumstances in which Parent (or the Guarantor pursuant to the Guarantee) is obligated to pay the Parent Termination Fee under Section 8.02(b)(i), upon payment of the Parent Termination Fee and, if applicable, the costs and expenses of the Company pursuant to Section 8.02(c) in accordance herewith, neither Parent nor the Guarantor shall have any further liability with respect to this Agreement or the transactions contemplated hereby to the Company or the holders of the Company Common Stock, and payment of the Parent Termination Fee and such costs and expenses by Parent (or the Guarantor pursuant to the Guarantee) shall be the Company's sole and exclusive remedy for any Claims, losses, liabilities, damages, judgments, inquiries, fines and reasonable fees, costs and expenses, including attorneys' fees and disbursements, suffered or incurred by the Company, the Company Subsidiaries or any other Person in connection with this Agreement, the transactions contemplated hereby (and the termination thereof) or any matter forming the basis for such termination, and the Company shall not have, and expressly waives and relinquishes, any other right, remedy or recourse (whether in contract or in tort or otherwise, or whether at law (including at common law or by statute) or in equity) with respect to this Agreement or the transactions contemplated hereby, including against any Financing Source Party; provided that, regardless of whether Parent pays or is obligated to pay the Parent Termination Fee, nothing in this Section 8.02(d) shall release Parent from liability for a Willful Breach of this Agreement. If this Agreement is terminated under circumstances in which the Company is obligated to pay the Company Termination Fee under Section 8.02(b)(ii) or Section 8.02(b)(iii), upon payment of the Company Termination Fee and, if applicable, the costs and expenses of Parent pursuant to Section 8.02(c) in accordance herewith, the Company shall have no further liability with respect to this Agreement or the transactions contemplated hereby to Parent, Merger Sub or any of their respective Affiliates or Representatives, and payment of the Company Termination Fee and such costs and expenses by the Company shall be Parent's sole and exclusive remedy for any Claims, losses, liabilities, damages, judgments, inquiries, fines and reasonable fees, costs and expenses, including attorneys' fees and disbursements, suffered or incurred by Parent, Parent's Affiliates and any other Person in connection with this Agreement, the transactions contemplated hereby (and the termination thereof) or any matter forming the basis for such termination, and Parent and Merger Sub shall not have, and each expressly waives and relinquishes, any other right, remedy or recourse (whether in contract or in tort or otherwise, or whether at law (including at common law or by statute) or in equity) with respect to this Agreement or the transactions contemplated hereby. The Parties acknowledge and agree that in no event shall the Company or Parent, as applicable, be required to pay the Company Termination Fee or the Parent Termination Fee, as applicable, on more than one occasion.

(e) For purposes of this Agreement, "**Willful Breach**" means a breach that is a consequence of an act or omission undertaken by the breaching Party with the Knowledge that the taking of or the omission of taking such act would, or would reasonably be expected to, cause or constitute a material breach of this Agreement; provided that, without limiting the meaning of Willful Breach, the Parties acknowledge and agree that any failure by any Party to consummate the Merger and the other transactions contemplated hereby after the applicable conditions to the closing set forth in Article VII have been satisfied or waived (except for those conditions that by their nature are to be satisfied at the Closing, which conditions would be capable of being satisfied at the time of such failure to consummate the Merger) shall constitute a Willful Breach of this Agreement. Parent and Merger Sub acknowledge and agree that, without in any way limiting the Company's rights under Section 9.10, recoverable damages of the Company hereunder shall not be limited to reimbursement of expenses or out-of-pocket costs but shall also include the benefit of the bargain lost by the shareholders of the Company (including "lost premium"), taking into consideration relevant matters, including the total amount payable to the Company's shareholders under this Agreement and the time value of money, which, in each case, shall be deemed in such event to be damages of the Company and shall be recoverable by the Company on behalf of its shareholders.

SECTION 8.03 Amendment. This Agreement may be amended by the parties at any time before or after receipt of the Company Shareholder Approval; provided, however, that (a) after receipt of the Company Shareholder Approval, there shall be made no amendment that by Law requires further approval by the shareholders of the Company without the further approval of such shareholders, (b) no amendment shall be made to this Agreement after the Effective Time, (c) except as provided above, no amendment of this Agreement shall require the approval of the shareholders of Parent or the shareholders of the Company and (d) no amendments to or waivers of any DFS Provision shall be effective without the written consent of the Financing Parties. This Agreement may not be amended except by an instrument in writing signed on behalf of each of the Parties.

SECTION 8.04 Extension; Waiver. At any time prior to the Effective Time, the parties may, subject to Section 8.03(a), (a) extend the time for the performance of any of the obligations or other acts of the other parties, (b) waive any inaccuracies in the representations and warranties contained herein or in any document delivered pursuant to this Agreement, (c) waive compliance with any covenants and agreements contained herein or (d) waive the satisfaction of any of the conditions contained herein. Any agreement on the part of a party to any such extension or waiver shall be valid only if set forth in an instrument in writing signed on behalf of such Party. The failure of any party to this Agreement to assert any of its rights under this Agreement or otherwise shall not constitute a waiver of such rights.

SECTION 8.05 Procedure for Termination, Amendment, Extension or Waiver. A termination of this Agreement pursuant to Section 8.01, an amendment of this Agreement pursuant to Section 8.03 or an extension or waiver pursuant to Section 8.04 shall, in order to be effective, require, in the case of the Company, Parent or Merger Sub, action by its respective board of directors or the duly authorized designee of its board of directors. Termination of this Agreement prior to the Effective Time shall not require the approval of the shareholders of the Company. The Party desiring to terminate this Agreement pursuant to Section 8.01 shall give written notice of such termination to the other Parties in accordance with Section 9.02, specifying the provision of this Agreement pursuant to which such termination is effected.

ARTICLE IX

GENERAL PROVISIONS

SECTION 9.01 Nonsurvival of Representations, Warranties, Covenants and Agreements; Contractual Nature of Representations and Warranties. None of the representations or warranties contained herein or in any instrument delivered pursuant to this Agreement shall survive, and all rights, Claims and causes of action (whether in contract or in tort or otherwise, or whether at law (including at common law or by statute) or in equity) with respect thereto shall terminate at, the Effective Time. Except for any covenant or agreement that by its terms contemplates performance after the Effective Time, none of the covenants or agreements of the Parties contained herein shall survive, and all rights, Claims and causes of action (whether in contract or in tort or otherwise, or whether at law (including at common law or by statute) or in equity) with respect to such covenants and agreements shall terminate at, the Effective Time. The Parties hereby acknowledge and agree that (a) all representations and warranties set forth in this Agreement are contractual in nature only, (b) if any such representation or warranty (as modified by the applicable Disclosure Letter) should prove untrue, the Parties' only rights, Claims or causes of action shall be to exercise the specific rights set forth in Section 7.02(a), Section 7.03(a), Section 8.01(c)(ii) and Section 8.01(d)(ii), as and if applicable, and (c) the Parties shall have no other rights, Claims or causes of action (whether in contract or in tort or otherwise, or whether at law (including at common law or by statute) or in equity) based on, arising out of or related to any such untruth of any such representation or warranty.

SECTION 9.02 Notices. All notices and other communications under this Agreement shall be in writing and shall be deemed given (a) when delivered personally by hand (with written confirmation of receipt by other than automatic means, whether electronic or otherwise), (b) when sent by facsimile or email (with written confirmation of transmission) or (c) one (1) Business Day following the day sent by an internationally recognized overnight courier (with written confirmation of receipt), in each case, at the following addresses, facsimile numbers and email addresses (or to such other address, facsimile number or email address as a Party may have specified by notice given to the other Party pursuant to this provision):

To Parent or Merger Sub:

Liberty Utilities (Central) Co.
c/o Algonquin Power & Utilities Corp.
354 Davis Rd, Suite 100
Oakville, Ontario, Canada L6J 2X1
Attn: Chief Executive Officer
Facsimile: (905) 465-4514

with a copy (which shall not constitute notice) to:

Liberty Utilities (Central) Co.
c/o Algonquin Power & Utilities Corp.
354 Davis Rd, Suite 100
Oakville, Ontario, Canada L6J 2X1
Attn: Chief General Counsel
Facsimile: (905) 465-4540

and with a copy (which shall not constitute notice) to:

Husch Blackwell LLP
4801 Main Street, Suite 1000
Kansas City, Missouri 64112
Attn: James G. Goettsch
Facsimile: (816) 983-8080

To the Company:

The Empire District Electric Company
602 S. Joplin Avenue
Joplin, Missouri 64801
Attn: Chief Executive Officer
Facsimile: (417) 625-5169

with a copy (which shall not constitute notice) to:

Cahill Gordon & Reindel LLP
80 Pine Street
New York, New York 10005
Attn: Michael Sherman
Facsimile: (212) 378-2598

SECTION 9.03 Definitions. For purposes of this Agreement, each capitalized term has the meaning given to it, or specified, in Exhibit A.

SECTION 9.04 Interpretation.

(a) Time Periods. When calculating the period of time before which, within which or following which any act is to be done or step taken pursuant to this Agreement, (i) the date that is the reference date in calculating such period shall be excluded and (ii) if the last day of such period is a not a Business Day, the period in question shall end on the next succeeding Business Day.

(b) Dollars. Unless otherwise specifically indicated, any reference herein to $ means U.S. dollars.

(c) Gender and Number. Any reference herein to gender shall include all genders, and words imparting the singular number only shall include the plural and vice versa.

(d) Articles, Sections and Headings. When a reference is made herein to an Article or a Section, such reference shall be to an Article or a Section of this Agreement unless otherwise indicated. The table of contents and headings contained herein are for reference purposes only and shall not affect in any way the meaning or interpretation of this Agreement.

(e) Include. Whenever the words "include," "includes" or "including" are used herein, they shall be deemed to be followed by the words "without limitation."

(f) Hereof. The words "hereof," "hereto," "hereby," "herein" and "hereunder" and words of similar import when used herein shall refer to this Agreement as a whole and not to any particular provision of this Agreement.

(g) Extent. The word "extent" in the phrase "to the extent" shall mean the degree to which a subject or other thing extends, and such phrase shall not mean simply "if."

(h) Contracts; Laws. Any Contract or Law defined or referred to herein means such Contract or Law as from time to time amended, modified or supplemented, unless otherwise specifically indicated.

(i) Persons. References to a person are also to its permitted successors and assigns.

(j) Exhibits and Disclosure Letters. The Exhibits to this Agreement and the Disclosure Letters are hereby incorporated and made a part hereof and are an integral part of this Agreement. Each of the Company and Parent may, at its option, include in the Company Disclosure Letter or the Parent Disclosure Letter, respectively, items that are not material in order to avoid any misunderstanding, and such inclusion, or any references to dollar amounts herein or in the Disclosure Letters, shall not be deemed to be an acknowledgement or representation that such items are material, to establish any standard of materiality or to define further the meaning of such terms for purposes of this Agreement or otherwise. Any matter set forth in any section of the Disclosure Letters shall be deemed to be referred to and incorporated in any section to which it is specifically referenced or cross-referenced and also in all other sections of such Disclosure Letter to which such matter's application or relevance is reasonably apparent. Any capitalized term used in any Exhibit or any Disclosure Letter but not otherwise defined therein shall have the meaning given to such term herein.

(k) Reflected On or Set Forth In. An item arising with respect to a specific representation, warranty, covenant or agreement shall be deemed to be "reflected on" or "set forth in" the Company Financial Statements included in the Company Reports, to the extent any such phrase appears in such representation, warranty, covenant or agreement if (i) there is a reserve, accrual or other similar item underlying a number on such balance sheet or financial statement reasonably related to the subject matter of such representation or (ii) such item and the amount thereof is otherwise reasonably identified on such balance sheet or financial statement (or the notes thereto).

SECTION 9.05 Severability. If any term or other provision of this Agreement is invalid, illegal or incapable of being enforced by any rule or Law, or public policy, all other conditions and provisions of this Agreement shall nevertheless remain in full force and effect so long as the economic or legal substance of the transactions contemplated hereby is not affected in any manner materially adverse to any Party or such Party waives its rights under this Section 9.05 with respect thereto. Upon any determination that any term or other provision is invalid, illegal or incapable of being enforced, the Parties shall negotiate in good faith to modify this Agreement so as to effect the original intent of the Parties as closely as possible in an acceptable manner to the end that transactions contemplated by this Agreement are fulfilled to the extent possible.

SECTION 9.06 Counterparts. This Agreement may be executed in one or more counterparts (including by means of facsimile or email in.pdf format), all of which shall be considered one and the same agreement, and shall become effective when one or more counterparts have been signed by each of the Parties and delivered to the other Parties.

SECTION 9.07 Entire Agreement; No Third-Party Beneficiaries. This Agreement, taken together with the Company Disclosure Letter, the Gurantee and the Confidentiality Agreement, constitutes the entire agreement, and supersedes all prior agreements and understandings, both written and oral, between or among the Parties with respect to the Merger. Except (a) for the right of the Company on behalf of its shareholders to pursue damages (including claims for damages contemplated by the last sentence of Section 8.02(e)) in the event of Parent's or Merger Sub's breach of this Agreement (whether or not this Agreement has been terminated pursuant to Article VIII), and (b) after the Effective Time, for Section 2.01, Section 2.02, Section 2.03, the last sentence of Section 6.02(a) and Section 6.09, each Party agrees that (i) their respective representations, warranties, covenants and agreements set forth herein are solely for the benefit of the other Parties, in accordance with and subject to the terms of this Agreement and (ii) this Agreement is not intended to, and does not, confer upon any Person other than the Parties any rights or remedies hereunder, including the right to rely upon the representations and warranties set forth herein. The Financing Parties and each of their respective Affiliates and their respective current, former and future direct or indirect equity holders, controlling persons, stockholders, agents, Affiliates, members, managers, general or limited partners, assignees or representatives (collectively, the "**Financing Source Parties**") shall be express third-party beneficiaries with respect to Section 8.02(d), Section 8.03, this Section 9.07, Section 9.08, Section 9.11(b), Section 9.12 and Section 9.14 (collectively, the "**DFS Provisions**").

SECTION 9.08 Governing Law. This Agreement, and all Claims or causes of action of the Parties (whether in contract or in tort or otherwise, or whether at law (including at common law or by statute) or in equity) that may be based on, arise out of or relate to this Agreement or the negotiation, execution, performance or subject matter hereof, shall be governed by and construed in accordance with the laws of the State of Delaware, without regard to principles of conflict of laws; provided, that, except as otherwise set forth in the Debt Letters as in effect as of the date of this Agreement, all matters relating to the interpretation, construction, validity and enforcement (whether at law, in equity, in contract, in tort, or otherwise) against any of the Financing Source Parties in any way relating to the Debt Letters or the performance thereof or the Financing, shall be exclusively governed by, and construed in accordance with, the domestic Law of the State of New York without giving effect to any choice or conflict of law provision or rule whether of the State of New York or any other jurisdiction that would cause the application of Law of any jurisdiction other than the State of New York.

SECTION 9.09 Assignment. Neither this Agreement nor any of the rights, interests or obligations under this Agreement shall be assigned, in whole or in part, by operation of law or otherwise, by any of the Parties without the prior written consent of the other Parties. Any purported assignment without such consent shall be void; provided that Parent may make as assignment of its rights (but not its obligations) under this Agreement to any Financing Party without the prior written consent of the Company. Subject to the preceding sentences, this Agreement will be binding upon, inure to the benefit of, and be enforceable by, the Parties and their respective successors and assigns.

SECTION 9.10 Specific Enforcement. The Parties acknowledge and agree that irreparable damage would occur in the event that any of the provisions of this Agreement were not performed in accordance with their specific terms or were otherwise breached and that monetary damages, even if available, would not be an adequate remedy therefor. It is accordingly agreed that, at any time prior to the termination of this Agreement pursuant to Article VIII, the Parties shall be entitled to an injunction or injunctions to prevent breaches of this Agreement and to enforce specifically the performance of terms and provisions of this Agreement, including the right of a Party to cause each other Party to consummate the Merger and the other transactions contemplated by this Agreement, in any court referred to in Section 9.11, without proof of actual damages (and each Party hereby waives any requirement for the securing or posting of any bond in connection with such remedy), this being in addition to any other remedy to which they are entitled at law or in equity. The Parties further agree not to assert that a remedy of specific enforcement is unenforceable, invalid, contrary to Law or inequitable for any reason, nor to assert that a remedy of monetary damages would provide an adequate remedy for any such breach. If any Party brings any Claim to enforce specifically the performance of the terms and provisions of this Agreement when expressly available to such Party pursuant to the terms of this Agreement, then, notwithstanding anything to the contrary herein, the End Date shall automatically be extended by the period of time between the commencement of such Claim and the date on which such Claim is fully and finally resolved.

SECTION 9.11 Jurisdiction; Venue.

(a) All Claims arising from, under or in connection with this Agreement shall be raised to and exclusively determined by the Court of Chancery of the State of Delaware or, if such court disclaims (or does not have) jurisdiction, the U.S. District Court for the District of Delaware, to whose jurisdiction and venue the Parties unconditionally consent and submit. Each Party hereby irrevocably and unconditionally waives any objection to the laying of venue of Claim arising out of this Agreement in such courts and hereby further irrevocably and unconditionally waives and agree not to plead or claim in any such court that any such Claim brought in any such court has been brought in an inconvenient forum. Each Party further agree that service of any process, summons, notice or document by U.S. registered mail to the respective addresses set forth in Section 9.02 hereof shall be effective service of process for any Claim brought against such Party in any such court.

(b) Notwithstanding anything to the contrary in this Agreement (including this Section 9.11), each Party agrees that it will not bring or support any action, cause of action, claim, cross-claim or third-party claim of any kind or description, whether in law or in equity, whether in contract or in tort or otherwise, against the Financing Source Parties in any way relating to this Agreement, including any dispute arising out of the Debt Letters or the performance thereof or the Financing, in any forum other than the Supreme Court of the State of New York, County of New York, or, if under applicable law exclusive jurisdiction is vested in the Federal courts, the United States District Court for the Southern District of New York (and of the appropriate appellate courts therefrom).

SECTION 9.12 Waiver of Jury Trial. **EACH PARTY HEREBY WAIVES, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW, ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF ANY SUIT, ACTION OR OTHER PROCEEDING ARISING OUT OF THIS AGREEMENT OR THE MERGER (INCLUDING ANY PROCEEDING AGAINST THE FINANCING SOURCE PARTIES ARISING OUT OF OR RELATED TO THE TRANSACTIONS CONTEMPLATED HEREBY, THE DEBT LETTERS, THE FINANCING OR THE PERFORMANCE OF SERVICES WITH RESPECT THERETO). EACH PARTY (A) CERTIFIES THAT NO REPRESENTATIVE, AGENT OR ATTORNEY OF ANY OTHER PARTY HAS REPRESENTED, EXPRESSLY OR OTHERWISE, THAT SUCH PARTY WOULD NOT, IN THE EVENT OF ANY ACTION, SUIT OR PROCEEDING, SEEK TO ENFORCE THE FOREGOING WAIVER AND (B) ACKNOWLEDGES THAT IT AND THE OTHER PARTIES HAVE BEEN INDUCED TO ENTER INTO THIS AGREEMENT BY, AMONG OTHER THINGS, THE MUTUAL WAIVER AND CERTIFICATIONS IN THIS SECTION 9.12.**

SECTION 9.13 Construction. Each of the Parties has participated in the drafting and negotiation of this Agreement. If an ambiguity or question of intent or interpretation arises, this Agreement must be construed as if it is drafted by all the Parties, and no presumption or burden of proof shall arise favoring or disfavoring any Party by virtue of authorship of any of the provisions of this Agreement.

SECTION 9.14 Financing Sources. Notwithstanding anything to the contrary contained in this Agreement, except for claims by Parent or the Merger Sub against the Financing Source Parties pursuant to the Debt Letters and any definitive documents related thereto, (a) none of the Parties nor any of their respective Subsidiaries, Affiliates, directors, officers, employees, agents, partners, managers, members or stockholders shall have any rights or claims against any Financing Source Party, in any way relating to this Agreement or any of the transactions contemplated by this Agreement, or in respect of any oral representations made or alleged to have been made in connection herewith or therewith, including any dispute arising out of or relating in any way to the Debt Letters or the performance thereof or the financings contemplated thereby, whether at law or equity, in contract, in tort or otherwise and (b) no Financing Source Party shall have any liability (whether in contract, in tort or otherwise) to any Party or any of their respective subsidiaries, Affiliates, directors, officers, employees, agents, partners, managers, members or stockholders for any obligations or liabilities of any Party under this Agreement or for any claim based on, in respect of, or by reason of, the transactions contemplated hereby and thereby or in respect of any oral representations made or alleged to have been made in connection herewith or therewith, including any dispute arising out of or relating in any way to the Debt Letters or the performance thereof or the financings contemplated thereby, whether at law or equity, in contract, in tort or otherwise.

SECTION 9.15 Transfer Taxes. All transfer, documentary, sales, use, stamp, registration and other such Taxes and fees (including penalties and interest) incurred in connection with the Merger and the other transactions contemplated by this Agreement shall be paid by Parent and Merger Sub when due.

[SIGNATURE PAGES FOLLOW]

IN WITNESS WHEREOF, the Parties have duly executed this Agreement, each as of the date first written above.

THE EMPIRE DISTRICT ELECTRIC COMPANY

By: /s/ Brad Beecher
Name: Brad Beecher
Title: President and Chief Executive Officer

LIBERTY UTILITIES (CENTRAL) CO.

By: /s/ Gregory S. Sorensen
Name: Gregory S. Sorensen
Title: President

By: /s/ Richard Leehr
Name: Richard Leehr
Title: Chief Financial Officer

LIBERTY SUB CORP.

By: /s/ Gregory S. Sorensen
Name: Gregory S. Sorensen
Title: President

By: /s/ Richard Leehr
Name: Richard Leehr
Title: Chief Financial Officer

EXHIBIT A

DEFINED TERMS

Section 1.01 Certain Defined Terms. For purposes of this Agreement, each of the following terms has the meaning specified in this Section 1.01 of Exhibit A:

"**Affiliate**" of any Person means another Person that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such first Person. For purposes of this definition, "**control**" (including the terms "**controlled by**" and "**under common control with**") means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of such Person, whether through ownership of voting securities, by contract or otherwise. For the avoidance of doubt, Emera, Inc. and its subsidiaries shall not be deemed to be Affiliates of Parent or Merger Sub.

"**Antitrust Laws**" means the Sherman Act, as amended, the Clayton Act, as amended, the HSR Act, the Federal Trade Commission Act, as amended, all applicable state, foreign or supranational antitrust Laws and all other applicable Laws issued by a Governmental Entity that are designed or intended to prohibit, restrict or regulate actions having the purpose or effect of monopolization or restraint of trade or lessening of competition through merger or acquisition.

"**Business Day**" means any day except for (a) a Saturday or a Sunday or (b) a day on which banking and savings and loan institutions are authorized or required by Law to be closed in New York, New York.

"**CFIUS**" means the Committee on Foreign Investment in the United States.

"**CFIUS Approval**" means (a) a written notice issued by CFIUS that it has concluded a review or investigation of the notification voluntarily provided pursuant to the DPA, with respect to the transactions contemplated by this Agreement and has terminated all action under Section 721 of the DPA or (b) if CFIUS has sent a report to the President of the United States requesting the President's decision and (i) the President has announced a decision not to take any action to suspend or prohibit the transactions contemplated by this Agreement or (ii) having received a report from CFIUS requesting the President's decision, the President has not taken any action after fifteen (15) days from the date the President received such report from CFIUS.

"**Claim**" means any demand, claim, suit, action, legal proceeding (whether at law or in equity) or arbitration.

"**Code**" means the Internal Revenue Code of 1986, as amended.

"**Company Benefit Agreement**" means each employment, consulting, bonus, incentive or deferred compensation, equity or equity-based compensation, severance, change-in-control, retention, termination or other material Contract between the Company or any Company Subsidiary, on the one hand, and any Company Personnel, on the other hand.

"**Company Benefit Plan**" means each (a) employee benefit plan (as defined in Section 3(3) of ERISA, whether or not subject to ERISA) or post-retirement or employment health or medical plan, program, policy or arrangement, (b) bonus, incentive or deferred compensation or equity or equity-based compensation plan, program, policy or arrangement, (c) severance, change-in control, retention or termination plan, program, policy or arrangement or (d) other compensation, pension, retirement, savings or other benefit plan, program, policy or arrangement, in each case, sponsored, maintained, contributed to or required to be maintained or contributed to by the Company or any Company Subsidiary for the benefit of any Company Personnel, or for which the Company or any Company Subsidiary has any direct or indirect liability.

"**Company Commonly Controlled Entity**" means any person or entity that, together with the Company, is treated as a single employer under Section 414 of the Code.

"**Company Material Adverse Effect**" means any fact, circumstance, effect, change, event or development that has a material adverse effect on the business, properties, financial condition or results of operations of the Company and the Company Subsidiaries, taken as a whole; provided that no fact, circumstance, effect, change, event or development resulting from or arising out of any of the following, individually or in the aggregate, shall constitute or be taken into account in determining whether a Company Material Adverse Effect has occurred: (a) any change or condition affecting any industry in which the Company or any Company Subsidiary operates, including electric generating, transmission or distribution industries or the natural gas distribution, production or transmission industries (including, in each case, any changes in the operations thereof); (b) system-wide changes or developments in electric transmission or distribution systems; (c) any change in customer usage patterns or customer selection of third-party suppliers for electricity; (d) any change affecting any economic, legislative or political condition or any change affecting any securities, credit, financial or other capital markets condition, in each case in the United States, in any foreign jurisdiction or in any specific geographical area; (e) any failure in and of itself by the Company or any Company Subsidiary to meet any internal or public projection, budget, forecast, estimate or prediction in respect of revenues, earnings or other financial or operating metrics for any period; (f) any change attributable to the announcement, execution or delivery of this Agreement or the pendency of the Merger, including (i) any action taken by the Company or any Company Subsidiary that is required or contemplated pursuant to this Agreement, or is consented to by Parent, or any action taken by Parent or any Affiliate thereof, to obtain any Consent from any Governmental Entity to the consummation of the Merger and the result of any such actions, (ii) any Claim arising out of or related to this Agreement (including shareholder litigation), (iii) any adverse change in supplier, employee, financing source, shareholder, regulatory, partner or similar relationships resulting therefrom or (iv) any change that arises out of or relates to the identity of Parent or any of its Affiliates as the acquirer of the Company; (g) any change or condition affecting the market for commodities, including any change in the price or availability of commodities; (h) any change in the market price, credit rating or trading volume of shares of Company Common Stock on the NYSE or any change affecting the ratings or the ratings outlook for the Company or any Company Subsidiary, (i) any change in applicable Law, regulation or GAAP (or authoritative interpretation thereof); (j) geopolitical conditions, the outbreak or escalation of hostilities, any act of war, sabotage or terrorism, or any escalation or worsening of any such act of war, sabotage or terrorism threatened or underway as of the date of this Agreement; (k) any fact, circumstance, effect, change, event or development resulting from or arising out of or affecting the national, regional, state or local engineering or construction industries or the wholesale or retail markets for commodities, materials or supplies (including equipment supplies, steel, concrete, electric power, fuel, coal, natural gas, water or coal transportation) or the hedging markets therefor, including any change in commodity prices; (l) any hurricane, tornado, ice storm, tsunami, flood, earthquake or other natural disaster or weather-related event, circumstance or development; (m) any finding of fact or order contained in any FERC, the FCC or any State Commission Judgment issued prior to the date hereof and applicable to the Company or the Company Subsidiaries; (n) any change or effect arising from (i) any rate cases, including the Proceedings, (ii) any requirements imposed by any Governmental Entities as a condition to obtaining the Company Required Statutory Approvals or the Parent Required Statutory Approvals or (iii) any other requirements or restrictions imposed by the FERC, the FCC or the State Commissions on the Company or the Company Subsidiaries; or (o) any fact, circumstance, effect, change, event or development that results from any shutdown or suspension of operations at any power plant from which the Company or any Company Subsidiary obtains electricity or facilities from which the Company or any Company Subsidiary obtains natural gas; provided, however, that any fact, circumstance, effect, change, event or development set forth in clauses (a), (b), (c), (d), (g), (i), (j) and (n)(iii) above may be taken into account in determining whether a Company Material Adverse Effect has occurred solely to the extent such fact, circumstance, effect, change, event or development has a materially disproportionate adverse effect on the Company and the Company Subsidiaries, taken as a whole, as compared to other entities (if any) engaged in the relevant business in the geographic area affected by such fact, circumstance, effect, change, event or development (in which case, only the incremental disproportionate impact may be taken into account in determining whether there has been, or would be, a Company Material Adverse Effect, to the extent such change is not otherwise excluded from being taken into account by clauses (a)–(o) of this definition).

"**Company Personnel**" means any current or former director, officer or employee of the Company or any Company Subsidiary.

"**Contract**" means any written or oral contract, lease, license, evidence of indebtedness, mortgage, indenture, purchase order, binding bid, letter of credit, security agreement, undertaking or other agreement that is legally binding.

"**Director Stock Unit**" means a common stock unit granted under the Director Stock Unit Plan.

"**Director Stock Unit Plan**" means The Empire District Electric Company Stock Unit Plan for Directors.

"**Disclosure Letters**" means, collectively, the Company Disclosure Letter and the Parent Disclosure Letter.

"**DPA**" means the Defense Production Act of 1950, as amended.

"**Employee Stock Purchase Plan**" means The Empire District Electric Company Employee Stock Purchase Plan.

"**Environmental Claim**" means any Claim against the Company or any Company Subsidiary asserted by any Person alleging liability (including liability for investigatory costs, cleanup costs, natural resources damages, property damages, personal injuries, or penalties) or responsibility arising out of, based on or resulting from (a) the presence or Release of, or exposure to, any Hazardous Materials at any location, or (b) any violation or alleged violation of Environmental Law or any Environmental Permit.

"**Environmental Laws**" means all applicable Laws relating to pollution, protection of, or damage to, the environment (including ambient air, surface water, groundwater, land surface, subsurface and sediments), natural resources climate change or human health and safety as it relates to the exposure to Hazardous Materials.

"**ERISA**" means the Employee Retirement Income Security Act of 1974, as amended.

"**Financing Failure**" means a refusal, for any reason, of the Financing Parties to provide the Financing in full or any other failure, for any reason, of the Financing to be provided in full, in each case, pursuant to, and in accordance with the terms and conditions of, the Debt Letters (or if definitive agreements relating to the Financing have been entered into, pursuant to such agreements).

"**Good Utility Practice**" means (a) any of the practices, methods and acts engaged in or approved by a significant portion of the electric generating, transmission or distribution industries or the industry or natural gas distribution, production or transmission industries, as applicable, during the relevant time period or (b) any of the practices, methods or acts that, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition; provided that Good Utility Practice is not intended to be limited to optimum practices, methods or acts to the exclusion of all others but rather to be acceptable practices, methods or acts generally accepted in the geographic location of the performance of such practice, method or act.

"**Governmental Entity**" means any U.S. or foreign federal, state, provincial or local governmental authority, court, government or self-regulatory organization, commission, tribunal or organization or any regulatory, administrative or other agency, or any political or other subdivision, department or branch of any of the foregoing, including any governmental, quasi-governmental or nongovernmental body administering, regulating, or having general oversight over gas, electricity, power, water, telecommunications, or similar commodity- or service-related markets, or any court, arbitrator, arbitration panel or similar judicial body.

"**Guarantor**" means Algonquin Power & Utilities Corp., a corporation organized under the laws of Canada.

"**Hazardous Materials**" means (a) petroleum, coal tar and other hydrocarbons and any derivatives or by-products, explosive or radioactive materials or wastes, asbestos in any form and polychlorinated biphenyls and (b) any other chemical, material, substance or waste that is regulated as a pollutant, a contaminant, hazardous or toxic under any Environmental Law.

"**Indebtedness**" means, with respect to any Person, without duplication, (a) all obligations of such Person for borrowed money (other than intercompany indebtedness), (b) all obligations of such Person evidenced by bonds, debentures, notes or similar instruments, (c) all obligations of such Person evidenced by letters of credit, bankers' acceptances or similar facilities to the extent drawn upon by the counterparty thereto, (d) all capitalized lease obligations of such Person and (d) all guarantees or other assumptions of liability for any of the foregoing.

"**Intellectual Property**" means all intellectual property and industrial property rights of any kind or nature, including all U.S. and foreign trademarks, service marks, service names, internet domain names, trade dress and trade names, and all goodwill associated therewith and symbolized thereby, patents and all related continuations, continuations-in-part, divisionals, reissues, reexaminations, substitutions, and extensions thereof, trade secrets, registered and unregistered copyrights and works of authorship, proprietary rights in databases to the extent recognized in any given jurisdiction, and registrations and applications for registration of any of the foregoing.

"**Judgment**" means a judgment, order, decree, ruling, writ, assessment or arbitration award of a Governmental Entity of competent jurisdiction.

"**Knowledge**" of any Person that is not an individual means, with respect to any matter in question, the actual knowledge of such Person's executive officers.

"**Law**" means any domestic or foreign, federal, state, provincial or local statute, law, ordinance, rule, binding administrative interpretation, regulation, order, writ, injunction, directive, judgment, decree or other requirement of any Governmental Entity, including the rules and regulations of the NYSE, the FERC, the FCC and the State Commissions.

"**Liberty Utilities**" means Liberty Utilities Co., a Delaware corporation, or any successor thereto as the U.S. holding company for the U.S. electric, natural gas and water distribution utility Affiliates of Parent.

"**Merger Consideration**" means Thirty-Four United States Dollars ($34.00) in cash.

"**NYSE**" means the New York Stock Exchange.

"**Organizational Documents**" means any corporate, partnership or limited liability organizational documents, including certificates or articles of incorporation, bylaws, certificates of formation, operating agreements (including limited liability company agreement and agreements of limited partnership), certificates of limited partnership, partnership agreements, shareholder agreements and certificates of existence, as applicable.

"**Parent Material Adverse Effect**" means any fact, circumstance, effect, change, event or development that has or would reasonably be expected to have a material and adverse effect on the ability of Parent or Merger Sub to consummate, or that would reasonably be expected to prevent or materially impede, interfere with or delay Parent or Merger Sub's consummation of, the transactions contemplated by this Agreement.

"**Performance-Based Restricted Stock Award**" means an award of performance-based restricted shares under either of the Stock Incentive Plans.

"**Permit**" means a franchise, license, permit, authorization, variance, exemption, order, registration, clearance or approval of a Governmental Entity.

"**Person**" means any natural person, firm, corporation, partnership, company, limited liability company, trust, joint venture, association, Governmental Entity or other entity.

"**Release**" means any release, spill, emission, leaking, dumping, injection, pouring, deposit, disposal, discharge, dispersal, leaching or migration into or through the environment (including ambient air, surface water, groundwater, land surface, subsurface and sediments).

"**State Commissions**" means the Arkansas Public Service Commission, the Kansas Corporation Commission, the Missouri Public Service Commission and the Oklahoma Corporation Commission.

"**Stock Incentive Plans**" means, collectively, The Empire District Electric Company 2015 Stock Incentive Plan and The Empire District Electric Company 2006 Stock Incentive Plan.

"**Subsidiary**" of any Person means another Person, an amount of the voting securities, other voting ownership or voting partnership interests of which is sufficient to elect at least a majority of its board of directors or other governing body (or, if there are no such voting interests, more than 50% of the equity interests of which) is owned directly or indirectly by such first Person.

"**Tax Return**" means all Tax returns, declarations, statements, reports, schedules, forms and information returns and any amended Tax return relating to Taxes.

"**Taxes**" means all taxes, customs, tariffs, imposts, levies, duties, fees or other like assessments or charges of a similar nature imposed by a Governmental Entity, together with all interest, penalties and additions imposed with respect to such amounts.

"**Time-Vested Restricted Stock Award**" means an award of time-vested restricted shares under either of the Stock Incentive Plans.

Section 1.02 Other Defined Terms. In addition to the defined terms set forth in Section 1.01 of this Exhibit A, each of the following capitalized terms has the respective meaning specified in the Section set forth opposite such term below:

Term	Section
Agreement	Preamble
Balance Sheet Date	3.06(b)
Bankruptcy and Equity Exceptions	3.04
Book-Entry Shares	2.02(b)(i)
Burdensome Effect	6.03(c)
Certificate	2.02(b)(i)
Certificate of Merger	1.02
Closing	1.03
Closing Date	1.03
Commitment Letter	4.06
Company	Preamble
Company Acquisition Agreement	5.03(b)
Company Adverse Recommendation Change	5.03(b)
Company Articles	3.01
Company Board	Recitals
Company Board Recommendation	3.04
Company Bylaws	3.01
Company Common Stock	2.01(a)(i)
Company Disclosure Letter	Article III
Company DRIP	5.01(a)(iv)
Company Employee	6.10(a)
Company Financial Advisor	3.20
Company Financial Statements	3.06(a)
Company Indemnified Parties	6.09(a)
Company Intervening Event	5.03(f)(iii)
Company Projections	3.22
Company Reports	3.06(a)
Company Required Consents	3.05(a)
Company Required Statutory Approvals	3.05(b)(iv)
Company Shareholder Approval	3.04
Company Shareholders Meeting	3.04
Company Subsidiaries	3.01
Company Takeover Proposal	5.03(f)(i)
Company Termination Fee	8.02(b)(ii)
Company Union Contracts	3.10
Company Voting Debt	3.03(b)
Confidentiality Agreement	6.02(b)
Consent	3.05(b)
Continuation Period	6.10(a)
Controlled Group Liability	3.09(d)
Debt Letters	4.06
Demand	2.02(i)

APPENDIX J

CONFIDENTIAL

APPENDIX K

LIBERTY UTILITIES
ORGANIZATION CHART
POST EMPIRE MERGER

NOTES

1. Unless otherwise indicated, the ownership of all entities is 100%.
2. Defined terms have the meaning ascribed to them in Algonquin Power & Utilities Corp's ("Algonquin") most recent Annual Information Form.
3. "Non-Algonquin" means that the entity in question would not satisfy the definition of an "APCo Entity" in Algonquin's credit agreement.
4. The highlighted boxes denote facilities/assets that are owned by the legal entities, not the legal entity.

KEY

1. Corporation or LLC ☐
2. Facility or Asset ☐

Chart A

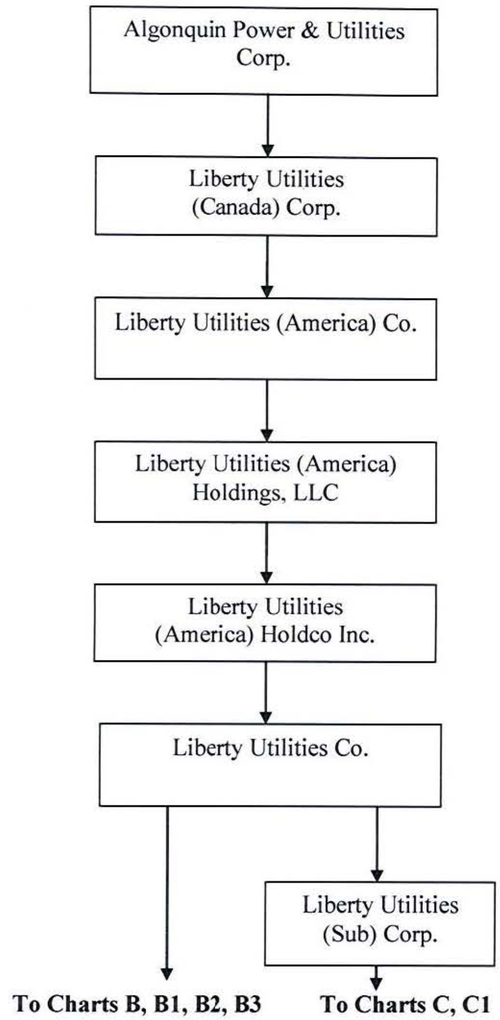

Algonquin Power & Utilities Corp.
Liberty Utilities (Canada) Corp.
Liberty Utilities (America) Co.
Liberty Utilities (America) Holdings, LLC
Liberty Utilities (America) Holdco Inc.
Liberty Utilities Co.
Liberty Utilities (Sub) Corp.
To Charts B, B1, B2, B3
To Charts C, C1

Chart B
(Continued on Chart B1, B2, B3)

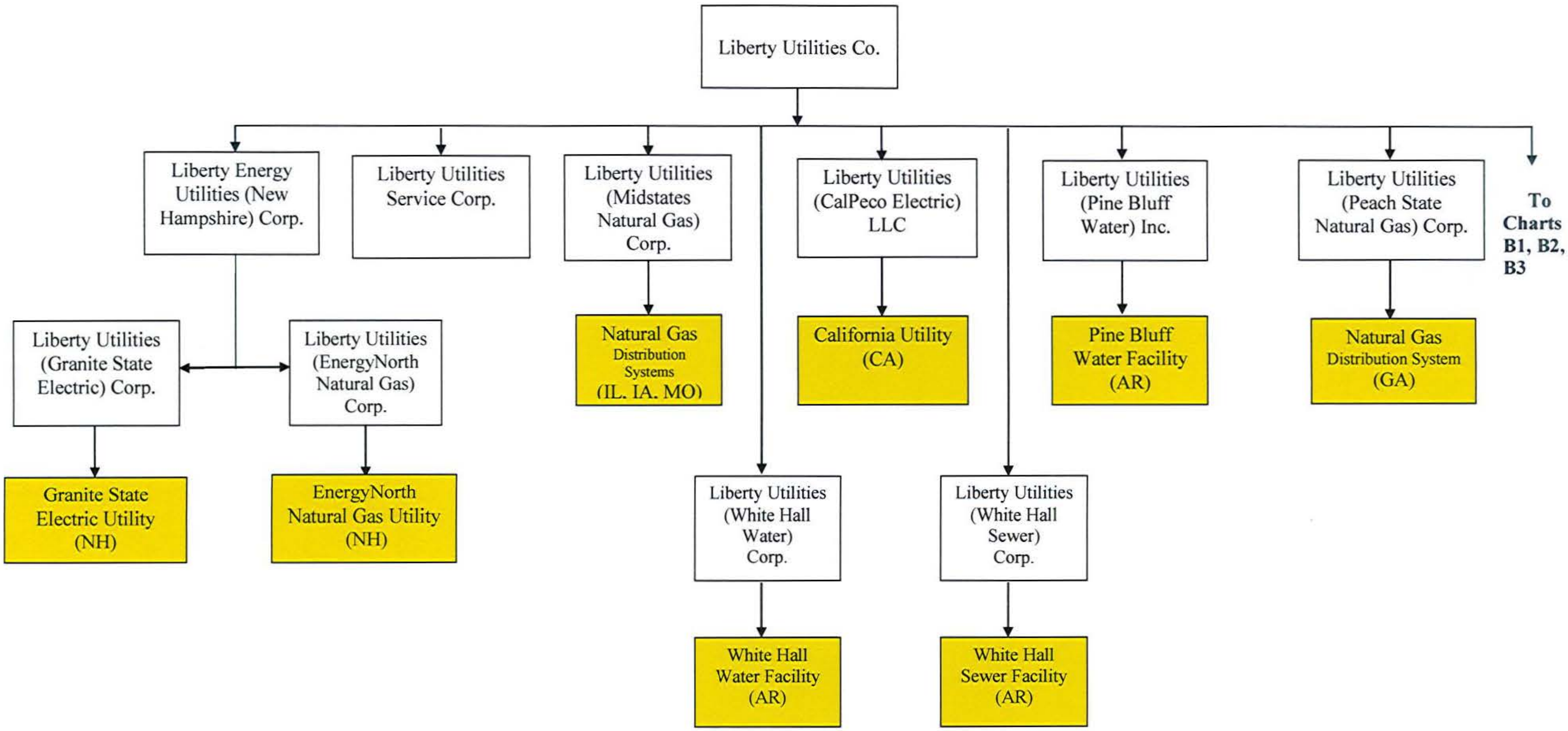


Chart B1

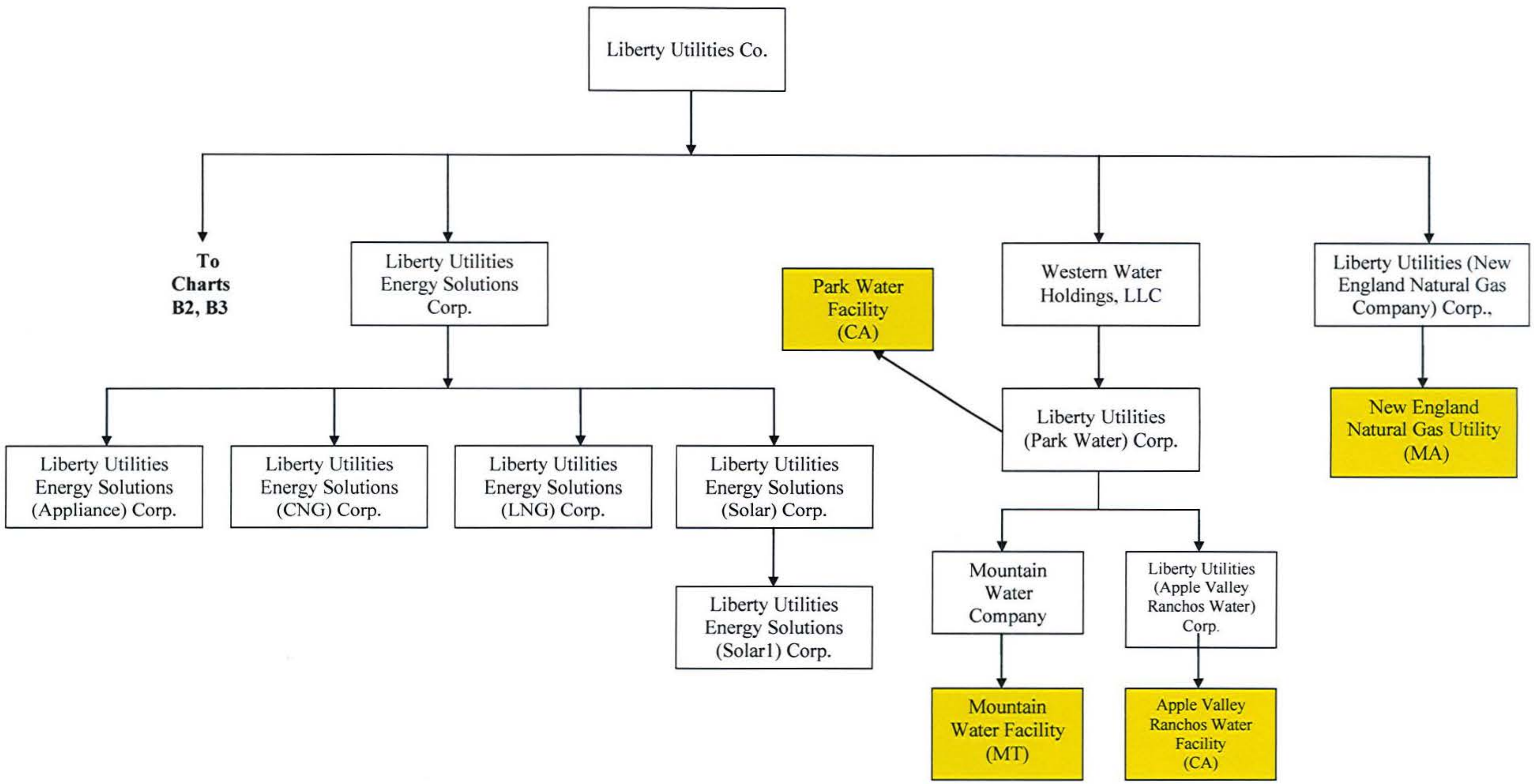
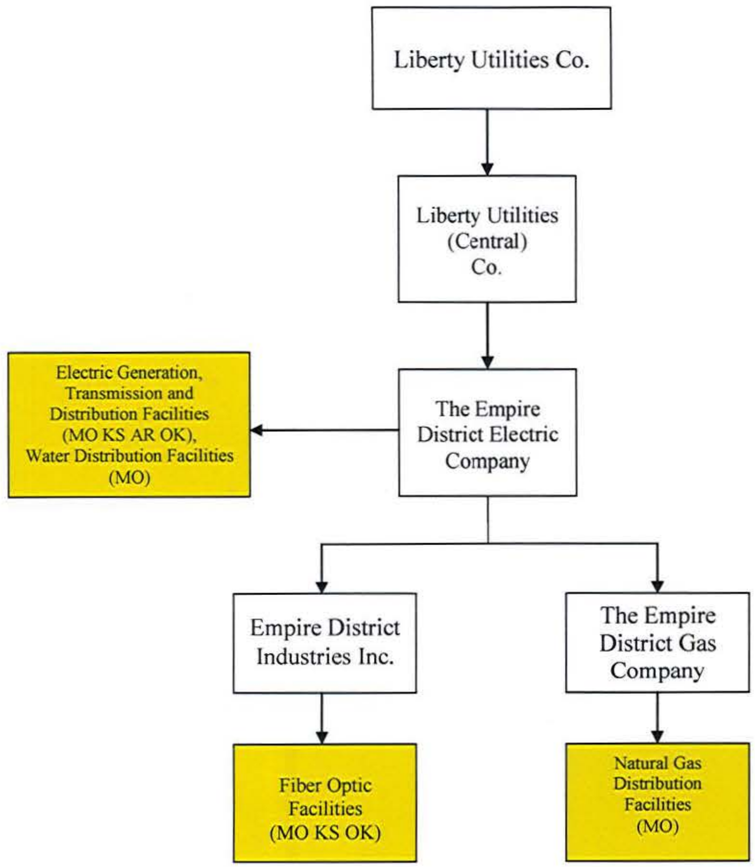

Liberty Utilities Co.
To Charts B2, B3
Liberty Utilities Energy Solutions Corp.
Park Water Facility (CA)
Western Water Holdings, LLC
Liberty Utilities (New England Natural Gas Company) Corp.,
Liberty Utilities Energy Solutions (Appliance) Corp.
Liberty Utilities Energy Solutions (CNG) Corp.
Liberty Utilities Energy Solutions (LNG) Corp.
Liberty Utilities Energy Solutions (Solar) Corp.
Liberty Utilities (Park Water) Corp.
New England Natural Gas Utility (MA)
Liberty Utilities Energy Solutions (Solar1) Corp.
Mountain Water Company
Liberty Utilities (Apple Valley Ranchos Water) Corp.
Mountain Water Facility (MT)
Apple Valley Ranchos Water Facility (CA)

Chart B2



Liberty Utilities Co.
Liberty Utilities (Central) Co.
The Empire District Electric Company
Electric Generation, Transmission and Distribution Facilities (MO KS AR OK), Water Distribution Facilities (MO)
Empire District Industries Inc.
The Empire District Gas Company
Fiber Optic Facilities (MO KS OK)
Natural Gas Distribution Facilities (MO)

Chart B3

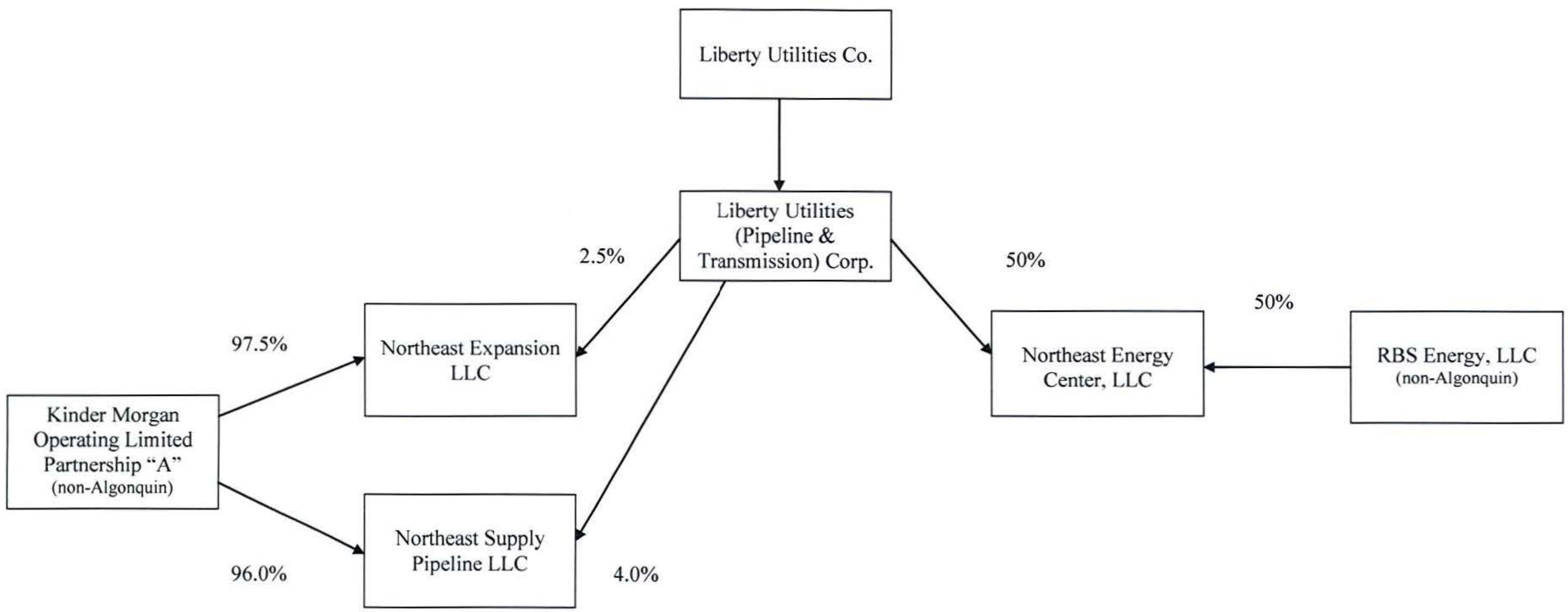

Liberty Utilities Co.
Liberty Utilities (Pipeline & Transmission) Corp.
2.5%
50%
50%
97.5%
Northeast Expansion LLC
Northeast Energy Center, LLC
RBS Energy, LLC
(non-Algonquin)
Kinder Morgan Operating Limited Partnership "A"
(non-Algonquin)
Northeast Supply Pipeline LLC
96.0%
4.0%

Chart C
(continued on Chart C1)

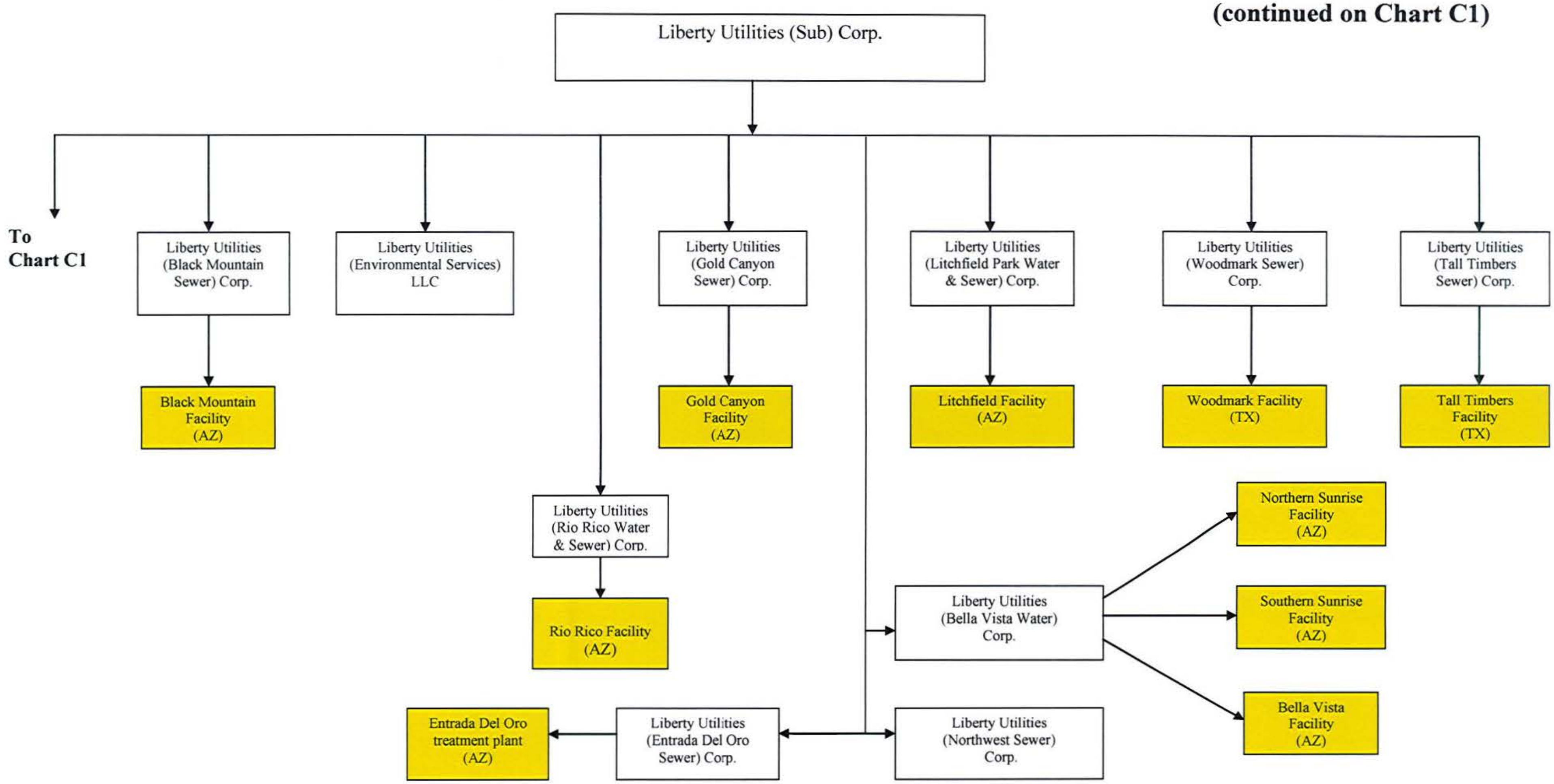
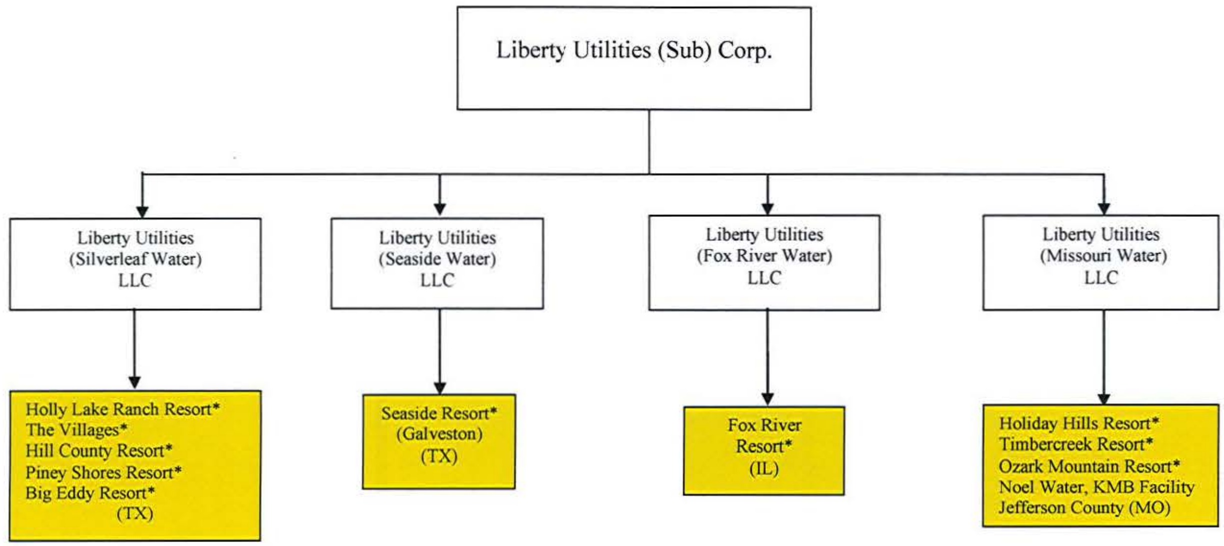


Chart C1



* Algonquin owns water treatment plants, water wells, lines, wastewater collection systems, rest line wastewater treatment plants and certain other assets located at these resorts.

APPENDIX L

Certified Copy of Resolutions

Passed by the Board of Directors

of

The Empire District Electric Company

on

February 9, 2016

I, DALE W. HARRINGTON, Secretary of The Empire District Electric Company, a corporation organized and existing under and by virtue of the laws of the State of Kansas (hereinafter called the "Company"), DO HEREBY CERTIFY that the following is a true and correct copy of resolutions adopted by the Board of Directors of the Company at a meeting duly called and held on the 9th day of February 2016; that at said meeting a majority of the Directors, constituting a quorum for the transaction of business, was present and voted in favor of said resolutions; and that said resolutions have not been amended or modified, rescinded or revoked but remain in full force and effect:

Merger Agreement

RESOLVED, that the form, terms and provisions of the Agreement and Plan of Merger (the "**Agreement**"), to be entered into by and among Liberty Utilities (Central) Co., a Delaware corporation ("**Parent**"), Liberty Sub Corp., a Kansas corporation ("**Merger Sub**"), and The Empire District Electric Company, a Kansas corporation (the "**Company**"), in the form presented to the Board of Directors of the Company (the "**Board**"), providing that Merger Sub will, on the terms and subject to the conditions set forth in the Agreement, merge with and into the Company (the "**Merger**"), with the Company as the surviving corporation, and the transactions contemplated by the Agreement, be, and they hereby are, adopted and approved and declared advisable; and be it

FURTHER RESOLVED, that the officers of the Company (the "**Authorized Officers**") be, and each of them hereby is, authorized, for and on behalf of the Company, to execute and deliver the Agreement, in the form presented to the Board, with such non-material changes, additions, or deletions therein as may be approved by the Authorized Officer of the Company executing the same, such execution and delivery to conclusively evidence the authorization and approval thereof by the Company, and each is hereby empowered to take any other action and make any such filings as such Authorized Officer deems necessary or desirable in connection with the execution, delivery and performance of the Agreement and the consummation of the transactions contemplated thereby, including the Merger; and be it

FURTHER RESOLVED, that the foregoing approvals constitute the approval of the Board, and the Board hereby approves, the Agreement and the transactions contemplated thereby, including the Merger, for all purposes under (1) the Kansas General Corporation Code, as amended, and (2) the Company's constituent documents.

Certificate of Merger

RESOLVED, that, if the Agreement is adopted by the Company's stockholders and the other closing conditions in the Agreement are satisfied or waived, then the Authorized Officers will be, and each of them hereby is, authorized and directed, for and on behalf of the Company, to execute and file with the Secretary of State of the State of Kansas a Certificate of Merger merging Merger Sub with and into the Company, and to pay, or cause to be paid, any and all costs, fees and expenses related thereto.

Special Meeting; Record Date

RESOLVED, that the Board has determined that the Agreement and the transactions contemplated thereby, including the Merger, are fair to, and in the best interests of, the Company and the Company's stockholders and hereby recommends that the stockholders of the Company adopt the Agreement; and be it

FURTHER RESOLVED, that adoption of the Agreement be submitted to a vote of the stockholders of the Company entitled to vote thereon at a special meeting of stockholders of the Company (the "**Special Meeting**"); and be it

FURTHER RESOLVED, that in accordance with Section 5 of Article II of the By-laws of the Company, the Secretary of the Company be, and he hereby is, authorized and directed to give notice of the Special Meeting to each stockholder of record entitled to notice at his or her last known post officer address not less than ten (10) nor more than fifty (50) days prior thereto; and be it

FURTHER RESOLVED, that the Chairman of the Board be and hereby is authorized to establish in advance a date, not exceeding sixty (60) nor less than ten (10) days preceding the date of the Special Meeting, as the record date for determination of stockholders entitled to vote at the Special Meeting; and be it

FURTHER RESOLVED, that the Authorized Officers be, and each of them hereby is, authorized, for and on behalf of the Company, to (i) fix the date, place and time for the Special Meeting, in compliance with the applicable law and the Company's constituent documents, (ii) adjourn or postpone the Special Meeting, if deemed necessary or appropriate by any Authorized Officer, including, if necessary, to permit further solicitation of proxies if there are not sufficient votes at the time of the Special Meeting to adopt the Agreement, and (iii) take such other actions as such

Authorized Officer deems necessary or desirable to implement the Special Meeting; and be it

FURTHER RESOLVED, that the Authorized Officers be, and each of them hereby is, authorized, for and on behalf of the Company, to engage one or more proxy solicitors, inspectors of elections and/or paying agents (such paying agent to be Wells Fargo Bank, National Association, or such other paying agent agreed to by the Company and Parent pursuant to the terms of the Agreement), as such Authorized Officers shall determine are necessary or desirable in connection with the Agreement, the Merger or the transactions contemplated thereby.

Proxy Materials

RESOLVED, that the preparation of preliminary and definitive copies of a letter to stockholders, notice of meeting of stockholders, proxy statement, form of proxy, and any other solicitation materials to be used in connection with obtaining stockholder approval of the Agreement and the Merger (collectively, the "**Proxy Materials**"), and appropriately responsive to the requirements of the Securities Exchange Act of 1934, as amended (the "**Exchange Act**") and other applicable laws, is authorized; and be it

FURTHER RESOLVED, that the Authorized Officers of the Company be, and they hereby are, authorized and directed, for the Company, to prepare or to cause to be prepared the Proxy Materials.

Filings

RESOLVED, that the Authorized Officers of the Company be, and they hereby are, authorized to execute and deliver all such other instruments, and to do all such other acts and things as the Authorized Officers, in their discretion, may deem necessary or desirable in connection with the execution, delivery, and performance of the Agreement by the Company and the satisfaction by the Company of the requirements related to the Agreement under any federal, state or local laws, rules or regulations relating to the regulation of the Company or its subsidiaries, or any other governmental statutes or regulations that are applicable to the Agreement or to the transactions contemplated thereby, including, without limitation, obtaining consents, approvals, orders, or other action from, or findings by, the appropriate regulatory authorities of Arkansas, Kansas, Missouri and Oklahoma, from the Securities and Exchange Commission (the "**SEC**") under the Securities Act of 1933 or the Exchange Act, from the Federal Energy Regulatory Commission under the Federal Power Act, from the Federal Communications Commission and from the Committee on Foreign Investment in the United States; and be it

FURTHER RESOLVED, that the Authorized Officers of the Company be, and they hereby are, authorized to execute and deliver all such other instruments, and to do all such other acts and things as the officers, in their discretion, may deem necessary or desirable in connection with the execution, delivery, and performance of the Agreement by the Company and the satisfaction by the Company of the requirements related to the Agreement under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, or any other governmental statutes or regulations that are applicable to the Agreement, the Merger or to the transactions contemplated thereby; and be it

FURTHER RESOLVED, that the Authorized Officers be, and each of them individually hereby is, authorized to file all such further documents and to provide such additional information and otherwise take all steps necessary and appropriate to satisfy all such filings and related requirements; and be it

FURTHER RESOLVED, that the filing of one or more Current Reports on Form 8-K under the Exchange Act and the Proxy Materials, with the SEC relating to (1) the Merger, (2) the execution and delivery of the Agreement and (3) the By-laws Amendment (as defined below), is authorized; and be it

FURTHER RESOLVED, that the Authorized Officers of the Company be, and they hereby are, authorized and directed, for the Company, to execute personally or by attorney-in-fact and to cause to be filed with the SEC said Form 8-Ks and the Proxy Materials, as applicable.

Directors Stock Unit Plan

RESOLVED, that the Stock Unit Plan for Directors of The Empire District Electric Company (the "**Plan**") be, and hereby is, effective upon and subject to the occurrence of the Merger, amended to provide that each Stock Unit credited under the Plan that is outstanding immediately prior to the Effective Time (as defined in the Agreement) shall be cancelled and converted, as of the Effective Time, into the right to receive payment of an amount in cash equal to the Merger Consideration (as defined in the Agreement) at the payment date elected or otherwise provided pursuant to the Plan, together with interest on such amount at the "U.S. Prime Rate" as quoted by the Wall Street Journal in effect at the Effective Time for the period, if any, from the Effective Time until the date of payment of such amount.

By-laws Amendment

RESOLVED, that the Amended and Restated By-laws of the Empire District Electric Company, amended as of February 6, 2014 are hereby amended and restated on the date hereof (the "**By-laws Amendment**") to add the following Article VII, Section 5:

"Unless the Company consents in writing to the selection of an alternative forum, the state court located in Shawnee County in the

State of Kansas (or, if such state court located in Shawnee County in the State of Kansas does not have jurisdiction, the United States District Court for the District of Kansas located in Shawnee County) shall be the sole and exclusive forum for (i) any derivative action or proceeding brought on behalf of the Company, (ii) any action asserting a claim for breach of a fiduciary duty owed by any director, officer, employee or agent of the Company to the Company or the Company's stockholders, (iii) any action asserting a claim arising pursuant to any provision of the Kansas General Corporation Code, the certificate of incorporation or the by-laws of the Company (as any may be amended from time to time) or (iv) any action asserting a claim governed by the internal affairs doctrine, in each case subject to said courts having personal jurisdiction over the indispensable parties named as defendants therein."

General

RESOLVED, that the Authorized Officers of the Company be, and each of them hereby is, authorized and empowered to do or cause to be done any and all things and to take or cause to be taken any and all actions including the negotiation, execution, delivery, acknowledgement, filing, recording and sealing of any and all certificates, notices, applications, agreements, opinions, papers, statements, instruments or other documents, the making of any expenditures, the obtaining of any necessary consents or waivers and to do or cause to be done any and all acts and things that may be necessary or in their judgment appropriate to effectuate the purpose and intent of these resolutions, or any of them, the Agreement, the transactions contemplated thereby and such other agreements and documents as may be executed by any Authorized Officer pursuant to authorization granted in these resolutions or to carry out the transactions contemplated thereby; and be it

FURTHER RESOLVED, that the Authorized Officers be, and each of them with full power to act without the others hereby is, authorized to pay all fees and expenses incurred by the Company in connection with the transactions contemplated by the Agreement and any actions or matters necessary or appropriate to give effect to the foregoing, including, but not limited to, all fees and expenses necessary or appropriate to effectuate the purpose and intent of the foregoing resolutions, or any of them, the Agreement, the transactions contemplated thereby and such other agreements and documents as may be executed by any Authorized Officer pursuant to authorization granted in these resolutions or to carry out the transactions contemplated thereby; and be it

FURTHER RESOLVED, that each Authorized Officer may authorize any other officer, employee or agent of, or counsel to, the Company or any of its subsidiaries to take any and all actions and to execute and deliver any and all certificates, documents, agreements and instruments referred to in these resolutions in place of or on behalf of such Authorized Officer, with full power as if such Authorized Officer were taking such action himself; and be it

FURTHER RESOLVED, that all actions previously taken by the officers of the Company in connection with the foregoing be, and they hereby are, ratified, approved and confirmed.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed the seal of the Company on this 9th day of February 2016.

Secretary

APPENDIX M

Certified Copy of Resolutions

Passed by the Board of Directors

of

Liberty Sub Corp.

on

February 9, 2016

I, TODD WILEY, Secretary of Liberty Sub Corp., a corporation organized and existing under and by virtue of the laws of the State of Kansas (hereinafter called the "Company"), DO HEREBY CERTIFY that the following is a true and correct copy of resolutions adopted by the Board of Directors of the Company at a meeting duly called and held on the 9th day of February 2016; that at said meeting a majority of the Directors, constituting a quorum for the transaction of business, was present and voted in favor of said resolutions; and that said resolutions have not been amended or modified, rescinded or revoked by remain in full force and effect:

WHEREAS, the Board deems it desirable and in the best interests of the Company for the Company to enter into and perform its obligations under, and to consummate the merger and other transactions contemplated by, that certain Agreement and Plan of Merger (the "Merger Agreement") among the Company, Liberty Utilities (Central) Co. ("Liberty Central"), and The Empire District Electric Company, in substantially the form attached hereto as Exhibit A, and all additional documents, agreements and certificates to be delivered by the Company thereunder, in each case with such changes as the Authorized Representatives of the Company, or any of them, deem necessary and desirable as conclusively evidenced by the execution thereof by any such Authorized Representative (the "Approved Agreements");

NOW, THEREFORE, BE IT RESOLVED, FURTHER RESOLVED, that the execution, delivery, and performance by the Company of the Approved Agreements, and the consummation of the merger and all other transactions contemplated thereby be, and they hereby are, authorized and approved in all respects;

FURTHER RESOLVED, that the Merger Agreement be submitted to Liberty Central, the sole stockholder of the Company, for approval, and the Board hereby recommends that Liberty Central approve, and advises Liberty Central to approve, the Company's execution, performance, and delivery of the Merger Agreement and the consummation of the merger and all other transactions contemplated thereby;

FURTHER RESOLVED, that for purposes of these resolutions and all actions taken in connection herewith, the "Authorized Representatives" of the Company shall include Ian Robertson, David Bronicheski, any officer or director of the Company, and any person to whom any of the foregoing may delegate any of their authority as an Authorized Representative;

FURTHER RESOLVED, that any two Authorized Representatives of the Company be, and each of them individually hereby is, authorized, empowered and directed, for and on behalf of the Company, to do, and to cause any and all of the Company's counsel and advisors to do, any and all acts, deeds and things, and to sign, seal, execute, acknowledge, file, record and deliver the Approved Agreements and any and all agreements, documents, instruments, notices, certificates or undertakings which may be or may become necessary, desirable or appropriate to effectuate the purposes of the foregoing resolutions, and to incur and pay all such fees and expenses as they shall in their good faith and judgment determine to be necessary, desirable or advisable to carry out fully the intent and purposes of the foregoing resolutions and the execution by them of any such document, instrument or agreement or the payment of any such fees and expenses or the doing by them of any act in connection with the foregoing matters shall conclusively establish their authority therefor and the approval of the documents, instruments or agreements so executed, the expenses so paid, the filings so made and the actions so taken;

FURTHER RESOLVED, that all actions heretofore taken by any officer, director or other Authorized Representative of the Company in connection with any matter referred to in or contemplated by any of the foregoing resolutions be, and hereby are, approved, ratified, and confirmed in all respects and

FURTHER RESOLVED, that this Consent will be in lieu of a special meeting of the Board and will be included in the minutes and filed with the records of the Company in place of any minutes of such meeting.

IN WITNESS WHEREOF, I have hereunto set my hand on this 15th day of March, 2016.

Secretary

Certified Copy of Resolutions

Passed by the Board of Directors

of

Liberty Utilities (Central) Co.

on

February 9, 2016

I, TODD WILEY, Secretary of Liberty Utilities (Central) Co., a corporation organized and existing under and by virtue of the laws of the State of Delaware (hereinafter called the "Company"), DO HEREBY CERTIFY that the following is a true and correct copy of resolutions adopted by the Board of Directors of the Company at a meeting duly called and held on the 9th day of February 2016; that at said meeting a majority of the Directors, constituting a quorum for the transaction of business, was present and voted in favor of said resolutions; and that said resolutions have not been amended or modified, rescinded or revoked by remain in full force and effect:

WHEREAS, the Board deems it desirable and in the best interests of the Company for the Company to enter into and perform its obligations under, and to consummate the merger and other transactions contemplated by, that certain Agreement and Plan of Merger (the "Merger Agreement") among the Company, Liberty Sub Corp., and The Empire District Electric Company, in substantially the form attached hereto as Exhibit A, and all additional documents, agreements and certificates to be delivered by the Company thereunder, in each case with such changes as any Authorized Representatives of the Company, or any of them, deem necessary and desirable as conclusively evidenced by the execution thereof by any such Authorized Representative (the "Approved Agreements");

NOW, THEREFORE, BE IT RESOLVED, FURTHER RESOLVED, that the execution, delivery, and performance by the Company of the Approved Agreements, and the consummation of the merger and all other transactions contemplated thereby be, and they hereby are, authorized and approved in all respects;

FURTHER RESOLVED, that for purposes of these resolutions and all actions taken in connection herewith, the "Authorized Representatives" of the Company shall include Ian Robertson, David Bronicheski, any officer or director of the Company, and any person to whom any of the foregoing may delegate any of their authority as an Authorized Representative;

FURTHER RESOLVED, that any two Authorized Representatives of the Company be, and each of them individually hereby is, authorized, empowered and directed, for and on behalf of the Company, to do, and to cause any and all of the Company's counsel and advisors to do, any and all acts, deeds and things, and to sign, seal, execute, acknowledge, file, record and deliver the Approved Agreements and any and all agreements, documents, instruments, notices, certificates or undertakings which may be or may become necessary, desirable or appropriate to effectuate the purposes of the foregoing resolutions, and to incur and pay all such fees and expenses as they shall in their good faith and judgment determine to be necessary, desirable or advisable to carry out fully the intent and purposes of the foregoing resolutions and the execution by them of any such document, instrument or agreement or the payment of any such fees and expenses or the doing by them of any act in connection with the foregoing matters shall conclusively establish their authority therefor and the approval of the documents, instruments or agreements so executed, the expenses so paid, the filings so made and the actions so taken;

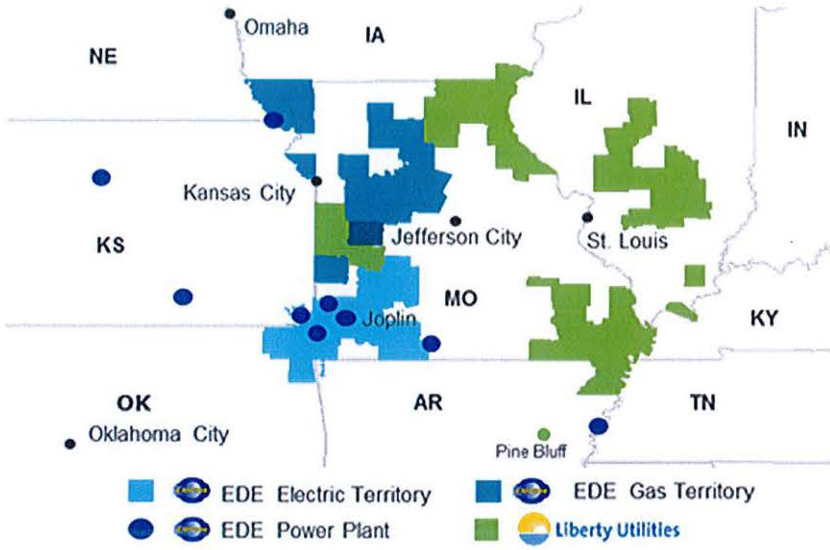
FURTHER RESOLVED, that all actions heretofore taken by any officer, director, or other Authorized Representative of the Company in connection with any matter referred to in or contemplated by any of the foregoing resolutions be, and hereby are, approved, ratified, and confirmed in all respects; and

FURTHER RESOLVED, that this Consent will be in lieu of a special meeting of the Board and will be included in the minutes and filed with the records of the Company in place of any minutes of such meeting.

IN WITNESS WHEREOF, I have hereunto set my hand on this 15th day of March, 2016.

Secretary

APPENDIX N



Omaha
IA
NE
IL
IN
Kansas City
KS
Jefferson City
St. Louis
MO
Joplin
KY
OK
AR
TN
Oklahoma City
Pine Bluff
EDE Electric Territory
EDE Gas Territory
EDE Power Plant
Liberty Utilities

APPENDIX O

ALGONQUIN POWER & UTILITIES CORP.

COST ALLOCATION MANUAL

V2014.1 Effective: July 1st, 2015

This document outlines the methods of direct charges and cost allocations: (i) between Algonquin Power & Utilities Corp. and its affiliates, including Algonquin Power Company and Liberty Utilities (Canada) Corp.; (ii) between Liberty Utilities (Canada) Corp. and its regulated utility subsidiaries; (iii) between Liberty Utilities (Canada) Corp.'s shared services functions and its affiliates, including Algonquin Power Company and Liberty Utilities (Canada) Corp.; and (iv) between Liberty Utilities Service Corp. and its affiliates.

TABLE OF CONTENTS

1. INTRODUCTION

The purpose of this manual is to provide a detailed explanation of services provided by Algonquin Power & Utilities Corp ("APUC"), and its affiliates, Algonquin Power Company ("APCo"), Liberty Utilities (Canada) Corp. ("LUC"), and Liberty Utilities Service Corp. ("LUSC") to the regulated utilities and to describe the Direct Charge[1] and Cost Allocation[2] Methodologies used by APUC, APCo, LUC, and LUSC. The following organization chart identifies the relationships between the separate entities.

Figure 1: Algonquin Power & Utilities Corporate Structure

This Cost Allocation Manual ("CAM") has been completed in accordance and conformance with the *NARUC Guidelines for Cost Allocations and Affiliate Transactions* ("NARUC Guidelines"). More specifically, the founding principles of this Cost Allocation Manual are to a) directly charge as much as possible to the entity that procures any specific service, and b) to ensure that inappropriate subsidization of unregulated activities by regulated activities, and vice versa, does not occur. For ease of reference, the NARUC Guidelines are attached as Appendix 1.

---

[1] Direct charges (sometimes referred to as assigned costs) are costs incurred by one company for the exclusive benefit of one or more other companies, and which are directly charged (or assigned) to the company or companies that specifically benefited.

[2] Allocated costs are costs incurred by one company that are for the benefit of either (a) all of the Algonquin companies or (b) all of the regulated companies, and which are charged to the benefited companies using a methodology and set of logical allocation factors that establish a reasonable link between cost causation and cost recovery.

Costs charged and allocated pursuant to this CAM shall include direct labor, direct materials, direct purchased services associated with the related asset or services, and overhead amounts. The direct charges are assigned as follows:

a. Tariffed rates or other pricing mechanisms established by rate setting authorities shall be used to provide all regulated services;
b. Services not covered by (a) shall be charged by the providing party to the receiving party at fully distributed cost; and
c. Facilities and administrative services rendered to a rate-regulated subsidiary shall be charged on the following basis:

   (i) the prevailing price for which the service is provided for sale to the general public by the providing party (i.e., the price charged to non-affiliates if such transactions with non-affiliates constitute a substantial portion of the providing party's total revenues from such transactions) or, if no such prevailing price exists, (ii) an amount not to exceed the fully distributed cost incurred by the providing party in providing such service to the receiving party.

2. THE APUC CORPORATE STRUCTURE

APUC's primary business is direct interest or equity ownership in renewable and thermal power generating facilities and regulated utilities. APUC owns a widely diversified portfolio of independent power production facilities[3] and regulated utilities[4] consisting of water distribution, wastewater treatment facilities, electric and gas utilities. While power production facilities are located in both Canada and the United States, regulated utility operations are exclusively in the United States. APUC is publicly traded on the Toronto Stock Exchange[5]. Its structure as a publicly traded holding company provides substantial benefits to its regulated utilities through access to capital markets.

[3] All power production (i.e. generation) facilities are found within Algonquin Power Company within the APUC corporate structure.

[4] All distribution utilities are found within Liberty Utilities (Canada) Corp. within the APUC corporate structure.

[5] Common shares and preferred shares are traded on the Toronto Stock Exchange (TSX) under the symbols AQN, AQN.PR.A and AQN.PR.D. Additional corporate information can be found at the company's website, algonquinpower.com.

APUC is the ultimate corporate parent and affiliate that provides financial, strategic management, corporate governance, administrative and support services to LUC and its subsidiaries as well as to the numerous generation assets held by APCo. The services provided by APUC are necessary for LUC and its subsidiaries to have access to capital markets for capital projects and operations. These services are expensed at APUC and are performed for the benefit of APCo and LUC and their respective businesses.

APUC and its affiliates capitalize on APUC's expertise and access to the capital markets through the use of certain shared services, which maximizes economies of scale and minimizes redundancy. In short, it provides for maximum expertise at lower costs. Further, the use of shared expertise allows each of the entities to receive a benefit they may not be able to achieve on a stand-alone basis such as strategic management advice and access to capital at more competitive rates.

3. SCOPE OF SERVICES FROM APUC AND APCO AMONG AFFILIATES AND HOW THOSE COSTS ARE DISTRIBUTED

Each distribution utility can be assigned and/or allocated costs from APUC, LUC and LUSC. This section provides an overview of the services and the cost methodology for APUC. In addition, this section also addresses any costs and services that may arise from APCo.

3.1 Labor Services and Cost Allocation from APUC to LUC and APCo

3.1.1 Description of the APUC Services and Costs

APUC provides benefits to its affiliate companies by use of certain shared services. APUC charges labor rates for these shared services at cost, which is the dollar hourly rate per employee as recorded in APUC's payroll systems, grossed up for burdens such as payroll taxes, health benefits, retirement plans, other insurance provided to employees, and other employee benefits. These labor costs are charged directly based on timesheets to the extent possible. If labor is for the benefit of all subsidiaries then the allocation methodologies used for non-labor costs are applied.

APUC's non-labor services include Financing Services. As used herein Financing Services means the selling of units to public investors in order to generate the funding and capital necessary (be it short term or long term funding, including equity and debt) for LUC and APCo as well as providing legal services in connection with the issuance of public debt.

The capital and funds obtained from the sale of shares in APUC are used by LUC and APCo for current and future capital investments. The services provided by APUC are critical and necessary to LUC and APCo because without those services they would not have a readily available source of capital funding. Further, relatively small utilities may have difficulty attracting capital on a stand-alone basis.

The services provided by APUC specifically optimize the performance of the utilities, keeping rates low for customers while ensuring access to capital is available. If the utilities did not have access to the services provided by APUC, then they would be forced to incur associated costs for financing, capital investment, audits, taxes and other similar services on a stand-alone basis, which would substantially increase such costs. Simply put, without incurring these costs, APUC would not be able to invest capital in its subsidiaries, including the regulated utilities.

In connection with the provision of Financing Services, APUC incurs the following types of costs: (i) strategic management costs (board of director, third-party legal services, accounting services, tax planning and filings, insurance, and required auditing); (ii) capital access costs (communications, investor relations, trustee fees, escrow and transfer agent fees); (iii) financial control costs (audit and tax expenses); and (iv) administrative (rent, depreciation, general office costs). See Appendix 2 for a more detailed discussion of the costs incurred by APUC.

Non-labor costs, excluding corporate capital, are pooled and allocated to LUC's subsidiaries and APCo using the method summarized in Table 1. Each corporate cost type, or function, has been carefully reviewed to properly identify the factors driving those costs. Each function or cost type is typically driven by more than one factor and each has been assigned an appropriate weighting. Table 1 includes brief commentary on the rationale for each cost driver and weighting, along with examples for each cost type.

Table 1: Summary of Corporate Allocation Method of APUC Indirect Costs

Type of Cost	Allocation Methodology		Rationale	Examples
Legal Costs	Net Plant Number of Employees O&M	33.3% 33.3% 33.3%	This function is driven by factors which include Net Plant, as typically the higher the value of plant, the more legal work it attracts; similarly, a greater number of employees are typically more indicative of larger facilities that require greater levels of attention; and O&M costs tend to be a third factor indicative of size and legal complexity.	Employee labor and related administration and programs; Third party legal
Tax Services	Revenue O&M Net Plant	33.3% 33.3% 33.3%	This function is driven by a variety of factors that influence the size and relative tax complexity, including Revenues, O&M and Net Plant. Tax activity can be driven by each of these factors.	Employee labor and related administration and programs, including Third party tax advice and services
Audit	Revenue O&M Net Plant	33.3% 33.3% 33.3%	This function is driven by a variety of factors that influence the size	Employee labor and related administration and programs,

			and complexity of Audit, including Revenues, O&M and Net Plant. Audit activity can be driven by each of these factors.	including Third party accounting and audit services
Investor Relations	Revenue O&M Net Plant	33.3% 33.3% 33.3%	This function is driven by factors which reflect the relative size and scope of each affiliate - Revenues, Net Plant and O&M costs.	Employee labor and related administration and programs, including third party Investor day communications and materials
Director Fees and Insurance	Revenue O&M Net Plant	33.3% 33.3% 33.3%	This function is driven by factors which reflect the relative size and scope of each affiliate - Revenues, Net Plant and O&M costs.	Board of Director fees, insurance and administration
Licenses, Fees and Permits	Revenue O&M Net Plant	33.3% 33.3% 33.3%	This function is driven by factors which reflect the relative size and scope of each affiliate - Revenues, Net Plant and O&M costs.	Third party costs
Escrow and Transfer Agent Fees	Revenue O&M Net Plant	33.3% 33.3% 33.3%	This function is driven by factors which reflect the relative size and scope of each affiliate - Revenues, Net Plant and O&M costs.	Third party costs

Other Professional Services	Revenue 33.3% O&M 33.3% Net Plant 33.3%	This function is driven by factors which reflect the relative size and scope of each affiliate - Revenues, Net Plant and O&M costs.	Third party costs
Office Administration	Oakville Employees 50% Square Footage 50%	This function is driven by factors which are indicative of number of employees and square footage utilized by these employees.	Office space and utility costs. Employee labor and related administration
Executives	Revenue 33.3% O&M 33.3% Net Plant 33.3%	This function is driven by factors which reflect the relative size and scope of each affiliate - Revenues, Net Plant and O&M costs.	Employee labor cost that is not directly attributable to any entity

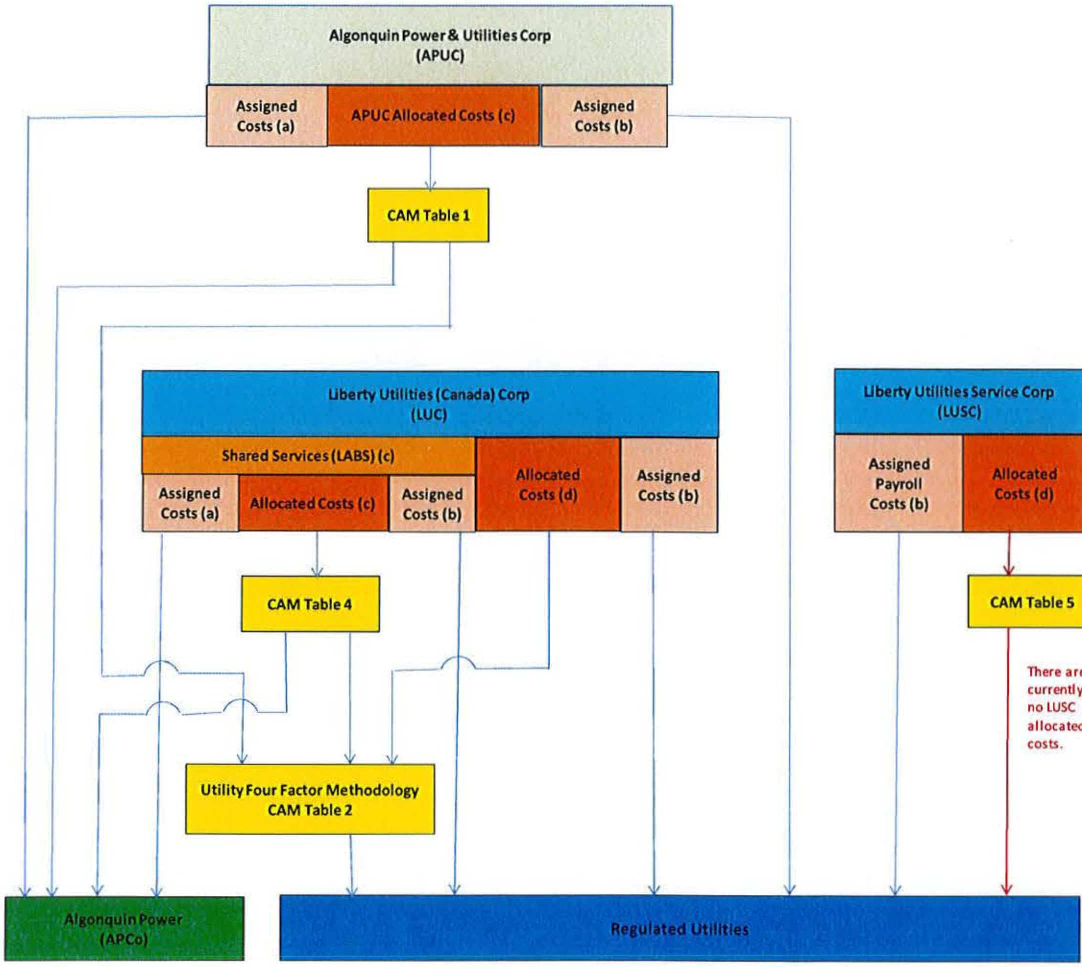
Notwithstanding the above, if a charge is related either solely to the regulated utility business, i.e., LUC, or to the power generation business, i.e., APCo, then all of those costs will be direct charged, or assigned, to the business segment for which they are incurred.

Lastly, if a cost can be directly attributable to a specific entity, it will be directly charged to that entity.

3.1.2 Description of the APUC Cost Flows

Please refer to Figure 2 for a diagram of the various flows of costs that may arise from each affiliate, including APUC.

Figure 2: Illustration of APUC Corporate Cost Distributions



(a) Costs that are directly assignable to unregulated companies
(b) Costs that are directly assignable to regulated companies
(c) Costs that benefit both unregulated and regulated operations
(d) Costs that benefit all regulated operations

As illustrated in Figure 2 and as described above, APUC incurs three types of costs that are passed on to its direct and indirect subsidiaries. The first type is APUC's costs that directly benefit a particular specific unregulated company, which are directly assigned to that unregulated company. The second type is APUC's costs that directly benefit a particular regulated company, which are directly assigned to that regulated company. The third type are APUC's remaining costs that benefit the entire enterprise (both regulated and unregulated), which are allocated between regulated and unregulated company groups pursuant to CAM Table 1. Information within Table 1 includes: (a) each type of cost incurred by APUC that is to be allocated between regulated and unregulated parts of the business; (b) the factors used to allocate each type of cost between regulated and unregulated activity; (c) the rationale for selecting the factors that are used for allocation; and (d) examples of the specific allocated costs. The costs allocated to the regulated companies as a group are then reallocated to individual companies using the Utility Four-Factor allocation methodology set forth in CAM Table 2 (described below), resulting in utility-specific allocated charges from APUC.

For an example of how an APUC invoice would be assigned or allocated, please see Appendix 3.

Certain costs, which are incurred for the benefit of APUC's businesses, are not allocated to any subsidiary. These include costs such as certain corporate travel and certain overheads.

3.2 Labor Services and Cost Allocation From APCo To LUC

From time to time, APCo may provide Engineering and Technical Labor to LUC or its utilities. These charges plus an allocation for corporate overheads such as rent, materials/supplies, etc. are capitalized and directly charged to the relevant utility.

From time to time, APCo employees may provide administrative support to LUC or its utilities. These charges are direct charged using time sheets.

4. SCOPE OF SERVICES PROVIDED BY LUC TO ITS SUBSIDIARIES, APUC AND APCO, AND HOW THOSE COSTS ARE DISTRIBUTED

Each distribution utility can be assigned and/or allocated costs from APUC, LUC and LUSC. This section provides an overview of the services and the cost methodology for LUC.

4.1 Overview of LUC Services and Costs

Please refer to Figure 2 for a diagram of the various flows of costs that may arise from each affiliate, including LUC.

As illustrated in Figure 2, LUC incurs three types of costs that are passed on to other direct or indirect subsidiaries. The first type is an LUC cost that directly benefits a particular regulated company, which is directly assigned to that regulated company. The second type is an LUC cost that benefits all of the regulated companies, which is allocated using the Utility Four-Factor Methodology described in CAM Table 2. Both of these cost types are described in section 4.2 below.

The third type of costs arising from LUC are those from shared services[6] that benefit both the regulated group of companies and the unregulated group of companies within the Liberty / Algonquin family, which are allocated between the two groups pursuant to the methodology described in section 4.3 and as set forth in CAM Table 4.

4.2 LUC Services and Costs Provided to Utilities

LUC provides its regulated utilities with the following services: accounting, administration, corporate finance, human resources (including training and development), information technology, rates and regulatory affairs, environment, health, safety, and security, customer service, procurement, risk management, legal, and utility planning. The following are examples of some of the services provided: (i) budgeting, forecasting, and financial reporting services including preparation of reports and preservation of records, cash management (including electronic fund transfers, cash receipts processing, managing short-term borrowings and investments with third parties); (ii) development of customer service policies and procedures; (iii) development of human resource policies and procedures; (iv) selection of information systems and equipment for accounting, engineering, administration, customer service, emergency restoration and other functions and implementation thereof; (v) development, placement and administration of insurance coverages and employee benefit programs, including group insurance and retirement annuities, property inspections and valuations for insurance; (vi) purchasing services including preparation and analysis of product specifications, requests for proposals and similar solicitations; and vendor and vendor-product evaluations; (vii) energy procurement oversight and load forecasting; and (viii) development of regulatory strategy.

LUC will assign costs that can be directly attributable to a specific utility. These include direct labor and direct non-labor costs. However, the indirect LUC costs cannot be directly attributed to an individual utility. LUC allocates its indirect

[6] As discussed later, LUC costs that benefit both regulated and unregulated businesses are incurred within Liberty Algonquin Business Services ("LABS"), which is a business unit within LUC that serves both regulated and unregulated entities.

labor and indirect non-labor costs, including capital costs, to its regulated utilities using a Utility Four-Factor Methodology. LUC uses the Utility Four-Factor Methodology to allocate costs incurred for the benefit of all of its regulated assets ("System-Wide Costs") to all of its utilities.

The Utility Four-Factor Methodology allocates costs by relative size of the utilities. The methodology used by LUC involves four allocating factors, or drivers: (1) Utility Plant; (2) Total Customers; (3) Non-Labor Expenses; and (4) Labor, with each factor assigned an equal weight, as shown in Table 2 below.

Table 2: Utility Four-Factor Methodology Factors and Weightings

Factor	Weight
Utility Plant	25%
Customer Count	25%
Non-Labor Expenses	25%
Labor	25%
Total	**100%**

LUC also uses the Utility Four-Factor Methodology to allocate to its regulated utilities the system-wide indirect labor and indirect non-labor costs allocated to LUC from APUC.

Table 3 provides a simplified hypothetical example to demonstrate how the Utility Four-Factor Methodology would be calculated based on ownership of only two hypothetical utilities.

Table 3: Utility Four-Factor Methodology Example

Factor	Utility 1	Utility 2	Total All Utilities	Utility 1 % of Total	Factor Weight	Utility 1 Allocation
Utility Plant ($)	727	371	1098	66%	25%	17%
Customer Count (#)	6000	1000	7000	86%	25%	21%
Labor ($)	57	32	89	64%	25%	16%
Non-Labor Expenses ($)	108	41	149	72%	25%	18%
Total Allocation						72%

As can be seen from these hypothetical numbers in Table 3, Utility 1 would be allocated 72% of the total indirect costs incurred by LUC, based on its relative size and application of the Utility Four-Factor Methodology. Utility 2 would be allocated the remaining 28%. LUC has developed and utilized this methodology to better allocate costs, recognizing that larger utilities require more time and management attention and incur greater costs than smaller ones.

On occasion there may be costs which are incurred for the benefit of two or more utilities, but not all of the utilities. These costs are directly assigned to utilities as per the vendor invoice, or, if the invoice doesn't specify a share for each utility, the Utility Four-Factor Methodology is used. In this situation, the weighting is determined by only including the utilities that benefited from the service and excluding the utilities that did not receive the service.

For an example of how an LUC invoice would be assigned or allocated, please see Appendix 4.

4.3 Shared Services from LUC

The third type of costs arising from LUC are those from shared services[7] that benefit both the regulated group of companies and the unregulated group of companies within the Liberty / Algonquin family.

Consistent with the organization practices described earlier, shared services and costs (within LUC) are assigned when they are directly attributable to a specific business unit[8]. Labor charges for LUC shared services staff are assigned using time sheets that depict the amount of time that is to be direct charged to either LUC or APCo.

Indirect costs for services from the shared services functions that cannot be directly assigned are allocated between the regulated and unregulated business units, LUC and APCo, pursuant to the methodology set forth in CAM Tables 4a and 4b. Similar to Table 1, Tables 4a and 4b include: (a) each type of cost incurred by LUC that is to be allocated between regulated and unregulated parts of the business; (b) the factors used to allocate each type of cost between regulated and

[7] Liberty Algonquin Business Services ("LABS") is a business unit found organizationally within LUC that serves both regulated and unregulated entities.

[8] To clarify, if a LABS service is for only one specific organization, such as the unregulated generation business, APCo, the cost will be directly charged to that business unit.

unregulated activity; (c) the rationale for selecting the factors that are used for allocation; and (d) examples of the specific allocated costs. The costs allocated to the regulated companies as a group are then reallocated to individual companies using the Utility Four-Factor Methodology set forth in CAM Table 2, resulting in utility-specific allocated charges from LUC.

For an example of how an invoice or cost within LUC's shared services (LABS) would be assigned or allocated, please see Appendix 5.

4.3.1 Business Services and Corporate Services

LUC shared services that benefit the entire company, i.e., APCo and LUC, are internally referenced under two names - Business Services and Corporate Services. The services and functions within each category are shown in the tables below[9]. Indirect costs from Business Services and Corporate Services are allocated using the following methodology shown in Tables 4a and 4b, respectively, which are designed to closely align the costs with the driver of the activity.

<u>Table 4a: Summary of Corporate Allocation Method of LUC Business Services Indirect Costs</u>

Type of Cost	Allocation Methodology	Rationale	Examples
Information Technology	Number of Employees 90% O&M 10%	IT function is driven by factors which include number of employees and O&M. The larger the number of employees, the more support, software and IT infrastructure is required.	Enterprise wide support, architecture, etc. Third party fees

[9] Note that the shared service functions found in Tables 4a and 4b are unchanged from those shown in Table 4 in the prior version of the CAM. These functions have simply been reorganized into these two Tables, 4a and 4b, to show the differentiation between Business Services and Corporate Services.

Human Resources	Number of Employees 100%	HR function is driven by number of employees. A greater number of employees requires additional HR support	HR policies, payroll processing, benefits, employee surveys
Training	Number of Employees 100%	Training is directly proportional to the number of employees per function	Courses, lectures, in house training sessions by third party providers
Facilities and Building Rent	Square Footage 100%	Office space occupied accurately reflects space requirements of each subsidiary	Corporate office building
Environment, Health, Safety and Security	Number of Employees 100%	EHSS training, etc. is directly proportional to the number of employees per function	Enterprise wide programs, employee labor and related administration
Procurement	O&M 50% Capital Expenditures 50%	Procurement function is based on typical proportion of expenditures	Enterprise wide support and related administration

Table 4b: Summary of Corporate Allocation Method of LUC Corporate Services Indirect Costs

Risk Management	Net Plant 33.3% Revenue 33.3% O&M 33.3%	This function is driven by factors which reflect the relative size and complexity of Risk Management - Revenues, Net Plant and O&M costs.	Software platform, fees and administration
Financial Reporting and Administration	Revenue 33.3% O&M 33.3% Net Plant 33.3%	This function is driven by factors which reflect the relative size and complexity of Financial Reporting and Admin. - Revenues, Net Plant and O&M costs.	Employee labor and related administration and third party fees
Treasury	Capital Expenditures 25% O&M 50% Net Plant 25%	Treasury activity is typically guided by the amount of necessary capex/plant for each utility, and operating costs/cash flow	Third party financing, employee labor and related administration and programs
Internal Audit	Net Plant 25% O&M 75%	This function is driven by factors which reflect the relative size and complexity of Internal audit activity. Larger Plant and operating costs drive of a given facility drive	Third party fees, employee labor and related administration and programs

		more activity from IA.	
Communications	Number of Employees 100%	Communications cost is directly proportional to the number of employees	Enterprise wide support and related administration
Legal Costs	Net Plant 33.3% Number of Employees 33.3% O&M 33.3%	This function is driven by factors which include Net Plant, as typically the higher the value of plant, the more legal work it attracts; similarly, a greater number of employees are typically more indicative of larger facilities that require greater levels of attention; and O&M costs tend to be a third factor indicative of size and legal complexity.	Employee labor and related administration and programs, including third party legal

5. LIBERTY UTILITIES SERVICE CORP.

Each distribution utility can be assigned and/or allocated costs from APUC, LUC and LUSC. This section provides an overview of the services and the cost methodology for LUSC.

All U.S.-based utility employees are employed, or will be employed, by Liberty Utilities Service Corp. (LUSC). All employees' costs, such as salaries, benefits, insurances etc. are to be paid by LUSC and direct charged to the company to which the employee is dedicated and performs work. Services provided from

LUSC to each regulated utility shall be done on a time sheet basis to the extent possible. In infrequent instances where time sheeting may not be possible, the allocation factors shown in Table 5 are to be used.

Table 5: Summary of Allocation Method of LUSC Indirect Costs

Type of Cost	Allocation Methodology	Rationale	Examples
Customer Care and Billing	Customer count 100%	Customer count accurately reflects the resource requirements of the Customer Care and Billing group	Customer Care and Billing employees and related administrations
IT/Tech Support	Number of Employees 100%	Technical support requirements are related to the number of employees	Tech support staff, associated administration, and required software, hardware, etc.
Human Resources	Number of Employees 100%	HR function is driven by number of employees. A greater number of employees requires additional HR support	HR policies, payroll processing, benefits, employee surveys
Gas Control	Net Plant 100%	The greater the plant, the more control required	Gas Control labor, administration, and associated programs
Legal	Net Plant 33.3% Number of Employees 33.3% O&M 33.3%	Allocated based on the relative size of affiliate and employee count.	Employee labor and related administration and programs, including third party legal

Regulatory	Net Plant 33.3% Number of Employees 33.3% O&M 33.3%	Allocated based on the relative size of affiliate and employee count.	Utility-wide studies or third party costs beneficial to all utilities
Environment, Health, Safety and Security	Number of Employees 100%	EHSS training, etc. is directly proportional to the number of employees	Utility-wide programs, employee labor and related administration
Procurement	O&M 50% Capital Expenditures 50%	Based on typical proportion of expenditures	Utility-wide support and related administration

Please note the allocation methodology can be adjusted based on the number of participating utilities. For example, Customer Service representatives who serve only the New Hampshire utilities will only have their indirect costs allocated, if any, based on the number of customers within New Hampshire. Labor costs associated with energy procurement are directly billed to the utilities requiring energy procurement services using timesheets.

6. CORPORATE CAPITAL

APUC or LUC will make capital investments for the benefit of all the utilities or facilities it owns (examples include corporate headquarters, IT systems, etc.). All capital investments kept at the corporate level benefiting all facilities will be distributed monthly in the form of an intercompany operating expense charge that captures the depreciation expense and cost of capital associated with the assets. All costs associated to service the investment will be allocated to APCo and LUC's utilities based on that department's allocation where the capital investment is made. For example, if the capital investment is made in Human Resources then the allocation methodology used for Human Resources to allocate non-capital indirect costs as shown in Table 4a will be used to allocate the charge associated with the corporate capital expenditures, including the cost of capital, depreciation, property tax, operation and maintenance costs and all other associated costs. Any corporate capital charges allocated to LUC are then reallocated to individual companies using the Utility Four-Factor Methodology set forth in CAM Table 2.

7. UPDATING ALLOCATIONS

Allocation percentages[10] are updated annually. These annual updates to the allocation percentages are based on the most recent audited financial statements and other actual, year-end information. The updated percentages come into effect each April 1st and are valid through to the following March 31st. These allocations percentages are also updated if an entity is either acquired or sold.

8. CAM TRAINING

The oversight of the CAM is currently the responsibility of the corporate Regulatory department. Any updates or revisions are coordinated and completed by this group. The CAM, and any support material, is distributed to Finance and Regulatory staff throughout the organization at least annually. Any revisions to the CAM are distributed immediately upon finalization to this same audience. Training sessions are conducted annually to Finance, Regulatory and other affected departments. As part of the employee orientation program, new employees receive an introduction to the CAM. Further enhancements and additions to this employee training program to foster and enhance the organization's understanding of the CAM are ongoing. For example, it is anticipated that an online training module will be created and deployed across the organization, supplemented by a self-certification process.

[10] To clarify, the factors and weightings are expected to remain constant. It is the underlying information used to calculate the allocation percentages that is updated annually, such as the most recent net plant figures, or the most recent numbers of employees, for example.

9. APPENDICES

APPENDIX 1 - NARUC GUIDELINES FOR COST ALLOCATIONS

Guidelines for Cost Allocations and Affiliate Transactions:

The following Guidelines for Cost Allocations and Affiliate Transactions (Guidelines) are intended to provide guidance to jurisdictional regulatory authorities and regulated utilities and their affiliates in the development of procedures and recording of transactions for services and products between a regulated entity and affiliates. The prevailing premise of these Guidelines is that allocation methods should not result in subsidization of non-regulated services or products by regulated entities unless authorized by the jurisdictional regulatory authority. These Guidelines are not intended to be rules or regulations prescribing how cost allocations and affiliate transactions are to be handled. They are intended to provide a framework for regulated entities and regulatory authorities in the development of their own policies and procedures for cost allocations and affiliated transactions. Variation in regulatory environment may justify different cost allocation methods than those embodied in the Guidelines.

The Guidelines acknowledge and reference the use of several different practices and methods. It is intended that there be latitude in the application of these guidelines, subject to regulatory oversight. The implementation and compliance with these cost allocations and affiliate transaction guidelines, by regulated utilities under the authority of jurisdictional regulatory commissions, is subject to Federal and state law. Each state or Federal regulatory commission may have unique situations and circumstances that govern affiliate transactions, cost allocations, and/or service or product pricing standards. For example, The Public Utility Holding Company Act of 1935 requires registered holding company systems to price "at cost" the sale of goods and services and the undertaking of construction contracts between affiliate companies.

The Guidelines were developed by the NARUC Staff Subcommittee on Accounts in compliance with the Resolution passed on March 3, 1998 entitled "Resolution Regarding Cost Allocation for the Energy Industry" which directed the Staff Subcommittee on Accounts together with the Staff Subcommittees on Strategic Issues and Gas to prepare for NARUC's consideration, "Guidelines for Energy Cost Allocations." In addition, input was requested from other industry parties.

Various levels of input were obtained in the development of the Guidelines from the Edison Electric Institute, American Gas Association, Securities and Exchange Commission, the Federal Energy Regulatory Commission, Rural Utilities Service and the National Rural Electric Cooperatives Association as well as staff of various state public utility commissions.

In some instances, non-structural safeguards as contained in these guidelines may not be sufficient to prevent market power problems in strategic markets such as the generation market. Problems arise when a firm has the ability to raise prices above market for a sustained period and/or impede output of a product or service. Such concerns have led some states to develop codes of conduct to govern relationships between the regulated utility and its non-regulated affiliates. Consideration should be given to any "unique" advantages an incumbent utility would have over competitors in an emerging market such as the retail energy market. A code of conduct should be used in conjunction with guidelines on cost allocations and affiliate transactions.

A. DEFINITIONS

1. Affiliates - companies that are related to each other due to common ownership or control.

2. Attestation Engagement - one in which a certified public accountant who is in the practice of public accounting is contracted to issue a written communication that expresses a conclusion about the reliability of a written assertion that is the responsibility of another party.

3. Cost Allocation Manual (CAM) - an indexed compilation and documentation of a company's cost allocation policies and related procedures.

4. Cost Allocations - the methods or ratios used to apportion costs. A cost allocator can be based on the origin of costs, as in the case of cost drivers; cost-causative linkage of an indirect nature; or one or more overall factors (also known as general allocators).

5. Common Costs - costs associated with services or products that are of joint benefit between regulated and non-regulated business units.

6. Cost Driver - a measurable event or quantity which influences the level of costs incurred and which can be directly traced to the origin of the costs themselves.

7. Direct Costs - costs which can be specifically identified with a particular service or product.

8. Fully Allocated costs - the sum of the direct costs plus an appropriate share of indirect costs.

9. Incremental pricing - pricing services or products on a basis of only the additional costs added by their operations while one or more pre-existing services or products support the fixed costs.

10. Indirect Costs - costs that cannot be identified with a particular service or product. This includes but not limited to overhead costs, administrative and general, and taxes.

11. Non-regulated - that which is not subject to regulation by regulatory authorities.

12. Prevailing Market Pricing - a generally accepted market value that can be substantiated by clearly comparable transactions, auction or appraisal.

13. Regulated - that which is subject to regulation by regulatory authorities.

14. Subsidization - the recovery of costs from one class of customers or business unit that are attributable to another.

B. COST ALLOCATION PRINCIPLES

The following allocation principles should be used whenever products or services are provided between a regulated utility and its non-regulated affiliate or division.

1. To the maximum extent practicable, in consideration of administrative costs, costs should be collected and classified on a direct basis for each asset, service or product provided.

2. The general method for charging indirect costs should be on a fully allocated cost basis. Under appropriate circumstances, regulatory authorities may consider incremental cost, prevailing market pricing or other methods for allocating costs and pricing transactions among affiliates.

3. To the extent possible, all direct and allocated costs between regulated and non-regulated services and products should be traceable on the books of the applicable regulated utility to the applicable Uniform System of Accounts. Documentation should be made available to the appropriate regulatory authority upon request regarding transactions between the regulated utility and its affiliates.

4. The allocation methods should apply to the regulated entity's affiliates in order to prevent subsidization from, and ensure equitable cost sharing among the regulated entity and its affiliates, and vice versa.

5. All costs should be classified to services or products which, by their very nature, are either regulated, non-regulated, or common to both.

6. The primary cost driver of common costs, or a relevant proxy in the absence of a primary cost driver, should be identified and used to allocate the cost between regulated and non-regulated services or products.

7. The indirect costs of each business unit, including the allocated costs of shared services, should be spread to the services or products to which they relate using relevant cost allocators.

C. COST ALLOCATION MANUAL (NOT TARIFFED)

Each entity that provides both regulated and non-regulated services or products should maintain a cost allocation manual (CAM) or its equivalent and notify the jurisdictional regulatory authorities of the CAM's existence. The determination of what, if any, information should be held confidential should be based on the statutes and rules of the regulatory agency that requires the information. Any entity required to provide notification of a CAM(s) should make arrangements as necessary and appropriate to ensure competitively sensitive information derived therefrom be kept confidential by the regulator. At a minimum, the CAM should contain the following:

1. An organization chart of the holding company, depicting all affiliates, and regulated entities.

2. A description of all assets, services and products provided to and from the regulated entity and each of its affiliates.

3. A description of all assets, services and products provided by the regulated entity to non-affiliates.

4. A description of the cost allocators and methods used by the regulated entity and the cost allocators and methods used by its affiliates related to the regulated services and products provided to the regulated entity.

D. AFFILIATE TRANSACTIONS (NOT TARIFFED)

The affiliate transactions pricing guidelines are based on two assumptions. First, affiliate transactions raise the concern of self-dealing where market forces do not necessarily drive prices. Second, utilities have a natural business incentive to shift costs from non-regulated competitive operations to regulated monopoly operations since recovery is more certain with captive ratepayers. Too much flexibility will lead to subsidization. However, if the affiliate transaction pricing guidelines are too rigid, economic transactions may be discouraged.

The objective of the affiliate transactions' guidelines is to lessen the possibility of subsidization in order to protect monopoly ratepayers and to help establish and preserve competition in the electric generation and the electric and gas supply markets. It provides ample flexibility to accommodate exceptions where the outcome is in the best interest of the utility, its ratepayers and competition. As with any transactions, the burden of proof for any exception from the general rule rests with the proponent of the exception.

1. Generally, the price for services, products and the use of assets provided by a regulated entity to its non-regulated affiliates should be at the higher of fully allocated costs or prevailing market prices. Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.

2. Generally, the price for services, products and the use of assets provided by a non-regulated affiliate to a regulated affiliate should be at the lower of fully allocated cost or prevailing market prices. Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.

3. Generally, transfer of a capital asset from the utility to its non-regulated affiliate should be at the greater of prevailing market price or net book value, except as

otherwise required by law or regulation. Generally, transfer of assets from an affiliate to the utility should be at the lower of prevailing market price or net book value, except as otherwise required by law or regulation. To determine prevailing market value, an appraisal should be required at certain value thresholds as determined by regulators.

4. Entities should maintain all information underlying affiliate transactions with the affiliated utility for a minimum of three years, or as required by law or regulation.

E. AUDIT REQUIREMENTS

1. An audit trail should exist with respect to all transactions between the regulated entity and its affiliates that relate to regulated services and products. The regulator should have complete access to all affiliate records necessary to ensure that cost allocations and affiliate transactions are conducted in accordance with the guidelines. Regulators should have complete access to affiliate records, consistent with state statutes, to ensure that the regulator has access to all relevant information necessary to evaluate whether subsidization exists. The auditors, not the audited utilities, should determine what information is relevant for a particular audit objective. Limitations on access would compromise the audit process and impair audit independence.

2. Each regulated entity's cost allocation documentation should be made available to the company's internal auditors for periodic review of the allocation policy and process and to any jurisdictional regulatory authority when appropriate and upon request.

3. Any jurisdictional regulatory authority may request an independent attestation engagement of the CAM. The cost of any independent attestation engagement associated with the CAM, should be shared between regulated and non-regulated operations consistent with the allocation of similar common costs.

4. Any audit of the CAM should not otherwise limit or restrict the authority of state regulatory authorities to have access to the books and records of and audit the operations of jurisdictional utilities.

5. Any entity required to provide access to its books and records should make arrangements as necessary and appropriate to ensure that competitively sensitive information derived therefrom be kept confidential by the regulator.

F. REPORTING REQUIREMENTS

1. The regulated entity should report annually the dollar amount of non-tariffed transactions associated with the provision of each service or product and the use or sale of each asset for the following:

a. Those provided to each non-regulated affiliate.
b. Those received from each non-regulated affiliate.
c. Those provided to non-affiliated entities.

2. Any additional information needed to assure compliance with these Guidelines, such as cost of service data necessary to evaluate subsidization issues, should be provided.

Source:
http://www.naruc.org/Publications/Guidelines%20for%20Cost%20Allocations%20and%20Affiliate%20Transactions.pdf

APPENDIX 2 – DETAILED EXPLANATION OF APUC COSTS

1. APUC Strategic Management Costs

Strategic management decisions are critical for any public utility. The need for strategic management is even more pronounced for APUC as a publicly traded company, which depends on access to capital funding through public sales of units. APUC seeks to hire talented strategic managers that aid in running each facility owned by the company as efficiently and effectively as possible. This ensures the long term health of each utility and ensures that rates are kept as low as possible without compromising the level of service. It also facilitates each regulated utility's access to necessary capital funding at reduced costs. The costs included in Strategic Management Costs fall into the following categories.

a. Board of Directors

The Board of Directors provides strategic oversight on all company affairs including high level approvals of strategy, operation and maintenance budgets, capital budgets, etc. In addition, the Board of Directors provides corporate governance and ensures that capital and costs are incurred prudently, which ultimately protects ratepayers.

b. General Legal Services

General legal services involve legal matters not specific to any single facility, including review of audited financial statements, annual information filings, Sedar filings, review of contracts with credit facilities, incorporation, tax issues of a legal nature, market compliance, and other similar legal costs. These legal services are required in order for APUC to provide capital funding to individual utilities, without which the utilities could not provide adequate service. Additionally, the services ensure that APUC's subsidiaries remain compliant in all aspects of operations and prevent those entities from being exposed to unnecessary risks.

c. Professional Services

Professional Services including strategic plan reviews, capital market advisory services, ERP System maintenance, benefits consulting, and other similar professional services. By providing these services at a parent level, the subsidiaries are able to benefit from economies of scale. Additionally, some of these services improve APUC's access to capital which benefits all of its subsidiaries.

2. Access to Capital Markets

One of APUC's primary functions is to ensure its subsidiaries have access to quality capital. APUC is listed on the Toronto Stock Exchange, a leading financial market. In order to allow its subsidiaries to have continued access to those capital markets, APUC incurs the following costs. These services and costs are a prerequisite to the subsidiaries continued access to those capital markets.

a. License and Permit Fees

In connection with APUC's participation in the Toronto Stock Exchange, APUC incurs certain license and permit fees such as Sedar fees, annual filing fees, licensing fees, etc. These licensing and permit fees are required in order to sell units on the Toronto Stock Exchange, which in turn provides funding for utility operations.

b. Escrow Fees

In connection with the payment of dividends to unit holders, APUC incurs escrow fees. Escrow fees are incurred to ensure continued access to capital and ensure continuing and ongoing investments by shareholders. Without such escrow fees, APUC's subsidiaries would not have a readily available source of capital funding.

c. Unit Holder Communications

Unit holder communication costs are incurred to comply with filing and regulatory requirements of the Toronto Stock Exchange and meet the expectations of shareholders. These costs include items such as news releases and unit holder conference calls. In the absence of shareholder communication costs, investors would not invest in the units of APUC, and in turn, APUC would not have capital to invest in its subsidiaries. With such communications services, the subsidiaries would not have a readily available source of capital funding.

3. APUC Financial Controls

Financial control costs incurred by APUC include costs for audit services and tax services. These costs are necessary to ensure that the subsidiaries are operating in a manner that meets audit standards and regulatory requirements, which have strong financial and operational controls, and financial transactions are recorded accurately and prudently. Without these services, the regulated utilities would not have a readily available source of capital funding.

a. Audit Fees

Audits are done on a yearly basis and reviews are performed quarterly on all facilities owned by APUC on an aggregate level. These corporate parent level audits reduce the cost of the stand-alone audits significantly for utilities which must perform its own separate audits. Where stand-alone audits are not required, ratepayers receive benefits of additional financial rigor, as well as access to capital, and financial soundness checks by third parties. Finally, during rate cases, the existence of audits provides staff and intervenors additional reliance on the company records, thus reducing overall rate case costs. The aggregate audit is necessary for the regulated utilities to have continued access to capital markets and unit holders.

b. Tax Services

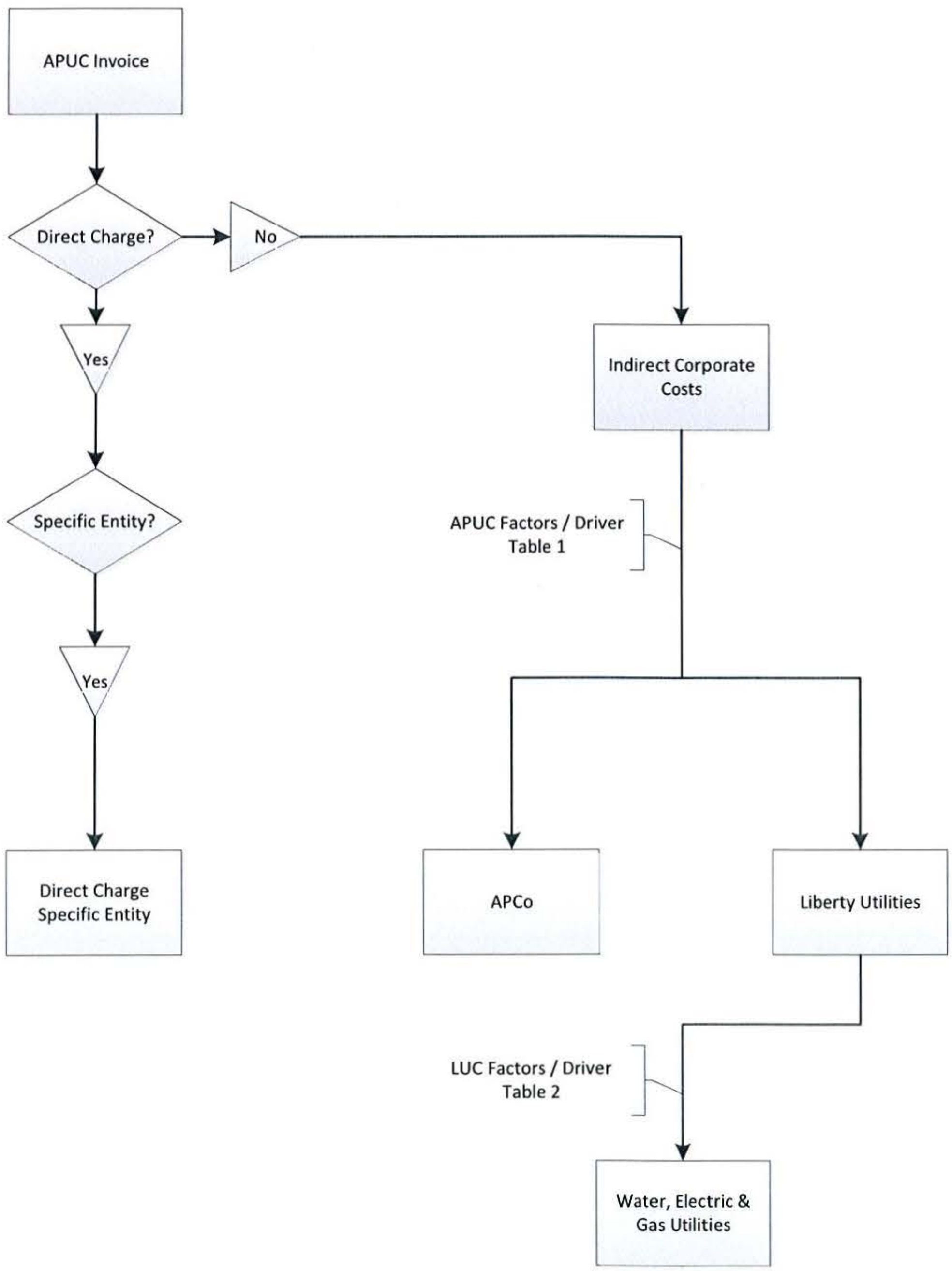
Taxes are paid on behalf of the regulated utilities at the parent level as part of a consolidated United States tax return. Tax services such as planning and filing are provided by third parties. Filing tax returns on a consolidated basis benefits each regulated utility by reducing the costs that otherwise would be incurred by such utility in filing its own separate tax return.

4. APUC ADMINISTRATIVE COSTS

Finally, administrative costs incurred by APUC such as rent, depreciation of office furniture, depreciation of computers, and general office costs are required to house all the services mentioned above. Without these administrative costs, the employees of APUC could not perform their work and provide the necessary services to the regulated utilities. These administrative costs also include training for corporate employees.

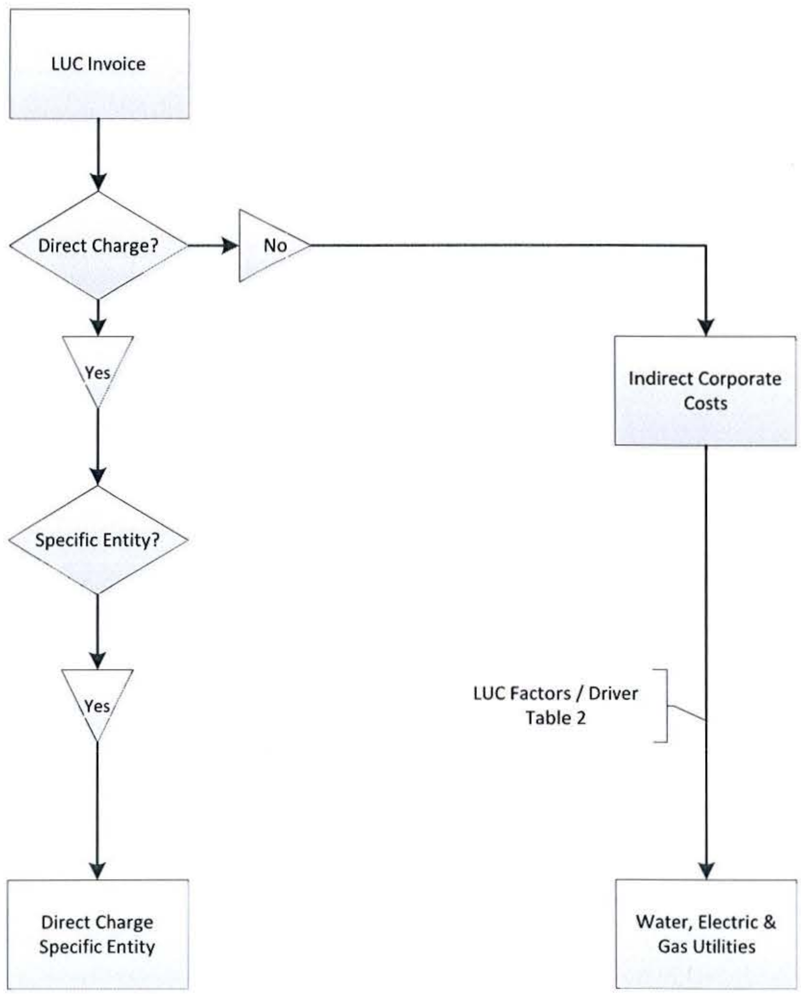
APPENDIX 3 – LIFE OF AN APUC INVOICE

A schematic is provided below showing the trail of an invoice received by APUC for services to be charged to its subsidiaries. The schematic is intended to visually explain the distribution of charges from APUC to APCo and Liberty Utilities companies.



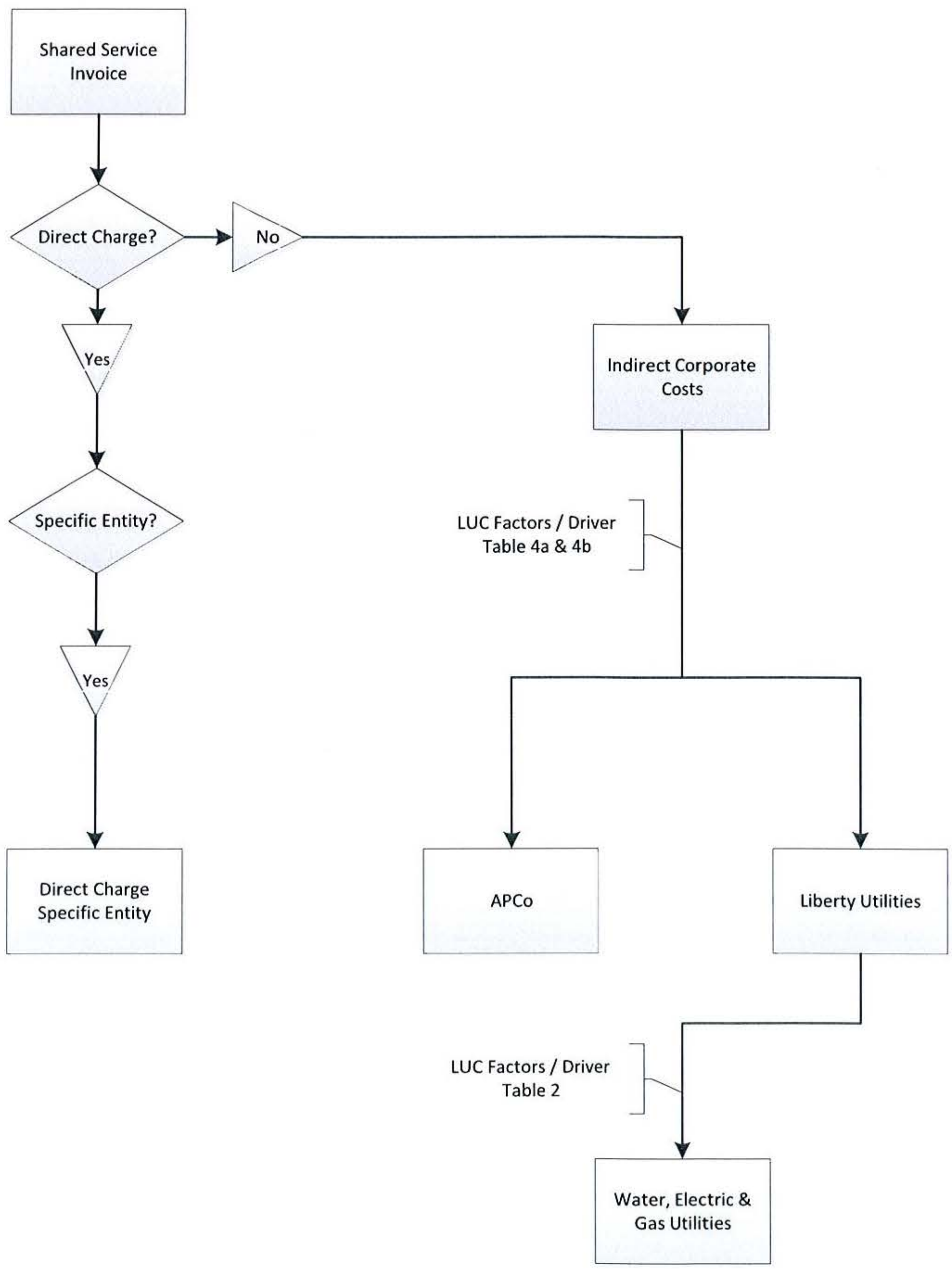
APPENDIX 4 – LIFE OF A LIBERTY UTILITIES INVOICE

A schematic is provided below showing the trail of an invoice received by Liberty Utilities (LUC) for services to be charged to its subsidiaries. The schematic is intended to visually explain the distribution of charges from LUC to Liberty Utilities companies.



APPENDIX 5 – LIFE OF A SHARED SERVICES INVOICE

A schematic is provided below showing the trail of an invoice for shared services provided within Liberty Utilities for services to be charged to affiliates and subsidiaries. The schematic is intended to visually explain the distribution of charges from shared services to APCo and Liberty Utilities companies.



APPENDIX P

THE EMPIRE DISTRICT ELECTRIC COMPANY

Consolidated Statements of Income

	Year Ended December 31,		
	2015	2014	2013
	(000's, except per share amounts)		
Operating revenues:			
Electric	$555,085	$592,491	$536,413
Gas	41,702	51,842	50,041
Other	8,786	7,997	7,876
	605,573	652,330	594,330
Operating revenue deductions:			
Fuel and purchased power	169,860	215,086	175,406
Cost of natural gas sold and transported	19,502	27,025	25,795
Regulated operating expenses	113,551	110,691	105,333
Other operating expenses	3,309	2,987	3,142
Maintenance and repairs	48,522	46,775	40,873
Loss on plant disallowance	—	86	2,409
Depreciation and amortization	80,550	73,185	69,306
Provision for income taxes	34,800	39,398	37,465
Other taxes	39,178	37,098	34,938
	509,272	552,331	494,667
Operating income	96,301	99,999	99,663
Other income and (deductions):			
Allowance for equity funds used during construction	4,850	6,420	3,853
Interest income	145	51	566
Benefit/(provision) for other income taxes	988	178	(27)
Other — non-operating expense, net	(3,429)	(1,302)	(1,218)
	2,554	5,347	3,174
Interest charges:			
Long-term debt	43,802	40,637	40,354
Short-term debt	266	113	60
Allowance for borrowed funds used during construction	(2,845)	(3,497)	(2,087)
Other	1,035	990	1,065
	42,258	38,243	39,392
Net income	**$ 56,597**	**$ 67,103**	**$ 63,445**
Weighted average number of common shares outstanding — basic	43,671	43,291	42,781
Weighted average number of common shares outstanding — diluted	43,718	43,314	42,803
Total earnings per weighted average share of common stock — basic	**$ 1.30**	**$ 1.55**	**$ 1.48**
Total earnings per weighted average share of common stock — Diluted	**$ 1.29**	**$ 1.55**	**$ 1.48**
Dividends declared per share of common stock	**$ 1.04**	**$ 1.025**	**$ 1.005**

The accompanying notes are an integral part of these consolidated financial statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY

Consolidated Statements of Common Stockholders' Equity

	Common Stock	Capital in excess of Par	Retained earnings	Total
		($-000's)		
Balance at December 31, 2012	$42,484	$628,199	$ 47,115	$717,798
Net income			63,445	63,445
Stock/stock units issued through:				
Stock purchase and reinvestment plans	560	11,326		11,886
Dividends declared			(43,006)	(43,006)
Balance at December 31, 2013	43,044	639,525	67,554	750,123
Net income			67,103	67,103
Stock/stock units issued through:				
Stock purchase and reinvestment plans	435	10,018		10,453
Dividends declared			(44,381)	(44,381)
Balance at December 31, 2014	43,479	649,543	90,276	783,298
Net income			56,597	56,597
Stock/stock units issued through:				
Stock purchase and reinvestment plans	342	7,923		8,265
Dividends declared			(45,430)	(45,430)
Balance at December 31, 2015	$43,821	$657,466	$101,443	$802,730

The accompanying notes are an integral part of these consolidated financial statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY

Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2015	2014	2013
		($-000's)	
Operating activities:			
Net income	$ 56,597	$ 67,103	$ 63,445
Adjustments to reconcile net income to cash flows from operating activities:			
Depreciation and amortization including regulatory items	88,801	82,754	71,734
Pension and other postretirement benefit costs, net of contributions	(9,184)	1,973	(1,888)
Deferred income taxes and unamortized investment tax credit, net	36,617	41,693	28,272
Allowance for equity funds used during construction	(4,850)	(6,420)	(3,853)
Stock compensation expense	4,082	4,057	2,984
Loss on plant disallowance	—	86	2,409
Non-cash loss on derivatives	6,994	1,245	14
Regulatory reversal of gain on sale of assets	—	44	1,236
Other	(625)	—	—
Cash flows impacted by changes in:			
Accounts receivable and accrued unbilled revenues	16,514	(24,174)	(14,312)
Fuel, materials and supplies	(3,151)	(8,121)	10,891
Prepaid expenses, other current assets and deferred charges	(4,863)	(6,051)	689
Accounts payable and accrued liabilities	(8,630)	1,141	(880)
Asset retirement obligation	(73)	(1,326)	(734)
Interest, taxes accrued and customer deposits	1,111	1,411	1,386
Other liabilities and other deferred credits	5,492	(4,192)	(3,942)
Net cash provided by operating activities	184,832	151,223	157,451

(Continued)

The accompanying notes are an integral part of these consolidated financial statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY

Consolidated Statements of Cash Flows (Continued)

	Year Ended December 31,		
	2015	2014	2013
		($-000's)	
Investing activities:			
Capital expenditures — regulated	$(183,206)	$(211,429)	$(152,524)
Capital expenditures and other investments — non-regulated	(2,243)	(1,998)	(2,259)
Restricted cash	—	(1,854)	1,485
Total net cash used in investing activities	(185,449)	(215,281)	(153,298)
Financing activities:			
Proceeds from first mortgage bonds, net	60,000	60,000	150,000
Long-term debt issuance costs	(818)	(651)	(1,879)
Proceeds from issuance of common stock, net of issuance costs	5,513	7,994	9,546
Redemption of senior notes	—	—	(98,000)
Net short-term borrowings (repayments)	(19,000)	40,000	(20,000)
Dividends	(45,430)	(44,381)	(43,006)
Other	—	(274)	(714)
Net cash provided by / (used) in financing activities	265	62,688	(4,053)
Net increase (decrease) in cash and cash equivalents	(352)	(1,370)	100
Cash and cash equivalents, beginning of year	2,105	3,475	3,375
Cash and cash equivalents, end of year	$ 1,753	$ 2,105	$ 3,475

	2015	2014	2013
Supplemental cash flow information:			
Interest paid	$ 42,858	$ 40,127	$ 39,033
Income taxes (refunded) paid, net of refund	(17,256)	23,103	10,584
Supplementary non-cash investing activities:			
Change in accrued additions to property, plant and equipment not reported above	$ (8,924)	$ 9,427	$ 5,420
Capital lease obligations for purchase of new equipment	$ 17	—	—

The accompanying notes are an integral part of these consolidated financial statements.

APPENDIX Q

Algonquin Power & Utilities Corp
Unaudited Pro Forma Consolidated Balance Sheet
September 30, 2015
(in millions of Canadian dollars)

	APUC	Empire	Pro Forma Adjustments	Pro forma Consolidated
Assets				
Currents assets:				
Cash and cash equivalents	$52	$2	$(1941) 3(b)	$55
			1000 3(c)	
			(40) 3(c)	
			(50) 3(c)	
			1078 3(d)	
			(13) 3(d)	
			(34) 3(e)	
Accounts receivable, net	146	124		270
Natural gas in storage	28	43		71
Supplies and consumables inventory	15	37		53
Regulatory assets	27	10		36
Prepaid expenses	15	42		56
Long-term investments	35			35
Deferred income taxes	23		11 3(c)	47
			13 3(c)	
Income taxes receivable	1			1
Derivative instruments	12	3		15
Other current assets	16	6		22
Total current assets	369	268	24	661
Property, plant and equipment, net	3718	2656		6374
Intangible assets, net	80			80
Goodwill	107	53	(53) 3(b)	1029
			923 3(b)	
Regulatory assets	208	270		477
Derivative instruments	76			76
Long-term investments	146			146
Deferred income taxes	38			38
Other assets	18	4		23
Total assets	4759	3251	894	8903
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities:				
Accounts payable	19	58		77
Accrued liabilities	139	61		200
Dividends payable	37			37
Regulatory liabilities	35	8		44
Long-term liabilities	22	22		44
Pension and other post-employment benefits				
Other long-term liabilities	43	20		63
Derivative instruments	7	6		12
Preferred shares, Series C	1			1
Income taxes liability	5	.		5
Deferred income taxes				
Total current liabilities	308	175	.	483
Long-term liabilities	1592	1140	1078 3(d)	3809
Regulatory liabilities	116	182		298
Deferred income taxes	201	546		747
Derivative Instruments	90	4		94
Pension and other post-employment benefits	154	100		254
Other long-term liabilities	185	33		218
Preferred shares, Series C	18			18
Redeemable non-controlling interest	11			11
Shareholders' equity:				.
Preferred shares	214			214
Common shares	1654	58	(58) 3(g)	2625
			1000 3(c)	
			(29) 3(c)	
Subscription receipts	111			111
Additional paid-in capital	37	875	(875) 3(g)	37
Deficit	(524)	137	(137) 3(g)	(608)
			(34) 3(e)	
			(37) 3(c)	
			(13) 3(d)	
Accumulated other comprehensive income	238			238
	1729	1071	(184)	2616
Non-controlling interest	356			356
Total stockholders' equity	2084	1071	(184)	2971
Total liabilities and shareholders equity	$4759	$3251	$894	$8903

See accompanying notes to unaudited pro forma consolidated financial statements

Algonquin Power & Utilities Corp
Unaudited Pro Forma Consolidated Statement of Operations
For the year ended December 31, 2014
(in millions of Canadian dollars)

	APUC	Empire	Pro Forma Adjustments		Pro Forma Consolidate
Revenue					
Regulated electricity distribution	$207	$652			$859
Regulated gas distribution	446	57			503
Regulated water reclamation and distribution	66	2			69
Non-regulated energy sales	202				202
Other revenue	22	9			31
	944	720			1664
Expenses					
Operating	236	147			383
Regulated fuel & electricity purchased	121	238			358
Regulated gas purchased	261	30			291
Non-regulated energy purchased	39				39
Administrative expenses	35	71			106
Depreciation of property, plant and equipment	109	80			189
Amortization of intangible assets	5				5
Other amortization		1			1
Gain on foreign exchange	(1)				(1)
	804	567			1371
Operating income from continuing operations	139	154			293
Interest expense	62	41	20	3(d)	124
Interest, dividend income and other income	(8)	(5)			(12)
Loss (gain) on sale of assets	-				-
Acquisition-related costs	3				3
Write-down of long-lived assets	8				8
	67	37	20		123
Earnings (loss) from operations before income taxes	72	117	(20)		170
Income tax expense (recovery)					
Current	4	(3)			1
Deferred	13	46	(8)	3(d)	52
	17	43	(8)		52
Earnings from continuing operations	56	74	(13)		117
Loss from discontinued operations, net of tax	(2)				(2)
Net earnings (loss)	54	74	(13)		115
Net earnings attributable to the non controlling interest	(22)				(22)
Net earnings (loss) attributable to Algonquin Power & Utilities Corp	$76	$74	$(13)		$137
Weighted average shares of common stock outstanding (in millions)					
Basic	214		94	3(h)	308
Diluted	216		94	3(h)	311
Basic net earnings per share from continuing operations	$ 0.32				$ 0.42
Basic net earnings per share	$ 0.31				$ 0.41
Diluted net earnings per share from continuing operations	$ 0.32				$ 0.42
Diluted net earnings per share	$ 0.31				$ 0.41

See accompanying notes to unaudited pro forma consolidated financial statements

Algonquin Power & Utilities Corp
Unaudited Pro Forma Consolidated Statement of Operations
Nine month period ended September 30, 2015
(in millions of Canadian dollars)

	APUC	Empire	Pro Forma Adjustments		Pro Forma Consolidated
Revenue					
Regulated electricity distribution	$170	$542			$711
Regulated gas distribution	350	39			389
Regulated water reclamation and distribution	58	2			60
Non-regulated energy sales	160				160
Other revenue	31	8			39
	768	591			1358
Expenses					
Operating	211	136			347
Regulated electricity purchased	101	169			269
Regulated gas purchased	168	19			187
Non-regulated energy purchased	23				23
Administrative expenses	27	59			87
Depreciation of property, plant and equipment	100	76			176
Amortization of intangible assets	4				4
Other amortization	4				4
Gain on foreign exchange	(3)				(3)
	635	458			1093
Operating income from continuing operations	132	133			265
Interest expense	49	39	15	**3(d)**	103
Interest, dividend income and other income	(6)	-			(7)
Loss (gain) on sale of assets	(3)				(3)
Acquisition-related costs	1				1
Write-down of long-lived assets	2				2
Loss (gain) on derivative financial instruments	(2)				(2)
	40	39	15		94
Earnings (loss) from operations before income taxes	92	94	(15)		171
Income tax expense (recovery)					
Current	7	-			6
Deferred	25	36	(6)	**3(d)**	55
	32	35	(6)		62
Earnings from continuing operations	60	59	(9)		110
Loss from discontinued operations, net of tax	(1)				(1)
Net earnings (loss)	59	59	(9)		109
Net earnings attributable to the non controlling interest	(20)				(20)
Net earnings (loss) attributable to Algonquin Power & Utilities Corp.	$79	$59	$(9)		$129
Weighted average shares of common stock outstanding (in millions)					
Basic	252		94	**3(h)**	346
Diluted	255		94	**3(h)**	349
Basic net earnings per share from continuing operations	$ 0.29				$ 0.35
Basic net earnings per share	$ 0.29				$ 0.35
Diluted net earnings per share from continuing operations	$ 0.28				$ 0.35
Diluted net earnings per share	$ 0.28				$ 0.35

See accompanying notes to unaudited pro forma consolidated financial statements

1. BASIS OF PRESENTATION

The accompanying unaudited pro forma consolidated financial statements give effect to the proposed acquisition (the "Acquisition") by Algonquin Power and Utilities Corp. ("APUC" or the "Company") of the Empire District Electric Company and its subsidiaries (collectively, "Empire") as described in the preliminary short form prospectus dated February 15, 2016 (the "Prospectus"). The accompanying unaudited pro forma consolidated financial statements have been prepared by management of APUC and are derived from the unaudited and audited consolidated financial statements of APUC as at and for the nine months ended September 30, 2015 and for the year ended December 31, 2014, respectively, and the unaudited and audited consolidated financial statements of Empire as at and for the nine months ended September 30, 2015 and for the year ended December 31, 2014, respectively.

The accompanying unaudited pro forma consolidated financial statements utilize accounting policies that are consistent with those disclosed in the Company's and Empire's audited consolidated financial statements as at December 31, 2014 and unaudited consolidated financial statements as at September 30, 2015 and were prepared in accordance with accounting principles generally accepted in the United States. The accompanying unaudited pro forma consolidated balance sheet and unaudited pro forma consolidated statements of operations reflect the Acquisition as if it had closed on September 30, 2015 and January 1, 2014, respectively. The accompanying unaudited pro forma consolidated financial statements may not be indicative of the results that would have been achieved if the transactions reflected therein had been completed on the dates indicated or the results which may be obtained in the future. For instance, the actual purchase price allocation will reflect the fair value, at the purchase date, of the assets acquired and liabilities assumed based upon the Company's evaluation of such assets and liabilities following the closing of the Acquisition and, accordingly, the final purchase price allocation, as it relates principally to goodwill, may differ materially from the preliminary allocation reflected herein.

The accompanying unaudited pro forma consolidated financial statements should be read in conjunction with the description of the Acquisition and the financing thereof provided in the Prospectus; the audited and unaudited consolidated financial statements of Empire, including the notes thereto, included in the Prospectus; and the audited and unaudited consolidated financial statements of APUC, including the notes thereto, incorporated by reference in the Prospectus.

Certain amounts in the historical financial statements of Empire have been reclassified in the pro forma balance sheet and statements of operations to reflect the presentation classifications in APUC's consolidated financial statements.

The underlying assumptions for the pro forma adjustments provide a reasonable basis for presenting the significant financial effect directly attributable to the Acquisition. These pro forma adjustments are tentative and are based on currently available financial information and certain estimates and assumptions. The actual adjustments to the consolidated financial statements will depend on a number of factors. Therefore, it is expected that the actual adjustments will differ from the pro forma adjustments, and the differences may be material.

2. DESCRIPTION OF TRANSACTION

Pursuant to an agreement and plan of a merger between Liberty Energy Utilities Co. ("Liberty Energy"), a direct wholly-owned subsidiary of APUC, and Empire, the Company will indirectly purchase all of the outstanding common shares of Empire for US$34.00 per share. Based on the purchase price calculation as detailed in the merger agreement dated February 9, 2016, the estimated net purchase price for the equity of Empire is approximately $1.9 billion (Note 3a). The Company will also assume Empire's consolidated debt, which was approximately US$876 million as at September 30, 2015.

The accompanying unaudited pro forma consolidated financial statements assume that at closing, the Acquisition will be financed through the net proceeds from a $1 billion common equity issuance (as further described below), with the balance initially funded through the Acquisition Credit Facility (as defined and described below).

The common equity is assumed to be issued through the 5% convertible unsecured subordinated debentures (the "Debentures") represented by instalment receipts offered on a public offering, all as described in the Prospectus. The company has also arranged a committed debt bridge facility for $2.2 billion repayable in full on the first anniversary following it's advance which together with existing cash and other sources available to APUC, an existing revolver and the Debentures represented by instalment receipts contemplated in the Prospectus, will fully fund the net purchase price and thereby ensure sufficient liquidity to close the Acquisition.

The accompanying unaudited pro forma consolidated financial statements assume that the Debentures will be issued and immediately fully converted into APUC common shares at the assumed closing date of the Acquisition. Therefore, the accompanying unaudited pro forma consolidated statements of operations do not recognize interest costs associated with the Debentures. The Company anticipates that the regulatory approval process prior to closing will be approximately 12 months. Due to many factors, including the timing of regulatory approval, the estimated closing period is subject to change which would change the amount of interest expense incurred on the Debentures, and the related income tax recovery. Interest costs associated with the Debentures are expected to be funded through operating cash flows and/or the Revolving Credit Facility.

3. PRO FORMA ASSUMPTIONS AND ADJUSTMENTS

(a) Purchase Price and Financing Structure

The following is the estimated net purchase price, estimated net funding requirements and assumed financing structure for the Acquisition. These estimates have been reflected in the accompanying unaudited pro forma consolidated financial statements.

Estimated Net Purchase Price		**Cdn$millions**
Estimated net purchase price, before assumed debt	$	3,115
Assumed debt of Empire		(1,174)
Estimated purchase price	$	1,941
Estimated Net Funding Requirements		
Estimated net purchase price before assumed long-term debt	$	1,941
Assumed debt of Empire		1,174
Common share issuance costs (Note 3(c))		40
Acquisition credit facility costs (Note 3(d))		13
Estimated acquisition costs (Note 3(e))		34
Interest on equity (Note 3(c))		50
Estimate net funding requirements	$	3,252
Assumed Financing Structure		
Assumed debt of Empire	$	1,174
Common share issuance (Note 3(c))		1,000
Acquisition credit facility (Note 3(d))		1,078
	$	3,252

(b) Allocation of estimated net purchase price

The estimated net purchase price has been allocated to the estimated fair values of Empire net assets and liabilities as at September 30, 2015 in accordance with the acquisition method, as follows:

Cdn$millions	Empire	FV and other adjustment	Net Total
Assets acquired			
Cash and cash equivalents	$2		$2
Restricted cash	6		6
Accounts receivable — trade, net	68		68
Accrued unbilled revenues	22		22
Accounts receivable — other	34		34
Fuel, materials and supplies	80		80
Prepaid expenses and other	42		42
Unrealized gain in fair value of derivative contracts	3		3
Regulatory assets	10		10
Total current assets	268		268
Property, plant and equipment, net	2680		2680
Regulatory assets	270		270
Goodwill	53	(53)	
Unamortized debt issuance costs	12		12
Other	4		4
Total assets	**$3287**	$(53)	**$3234**
Liabilities assumed			
Accounts payable and accrued liabilities	$73		$73
Current maturities of long-term debt			
Short-term debt	22		22
Regulatory liabilities	8		8
Customer deposits	19		19
Interest accrued	20		20
Unrealized loss in fair value of derivative contracts	6		6
Taxes accrued	26		26
Other current liabilities	1		1
Total current liabilities	175		175
Obligations under capital lease	5		5
First mortgage bonds and secured debt	1011		1011
Unsecured debt	136		136
Regulatory liabilities	182		182
Deferred income taxes	546		546
Unamortized investment tax credits	24		24
Pension and other postretirement benefit obligations	100		100
Unrealized loss in fair value of derivative contracts	4		4
Other	33		33
Liabilities associated with assets held for sale	**$2216**		**$2216**
Net assets at fair value, as at September 30, 2015	$1071		$1018
Estimated net purchase price, before assumed debt and acquisition costs			1941
Goodwill			$923

Based in Joplin, Missouri, Empire is an investor-owned, regulated utility providing electric, natural gas (through its wholly-owned subsidiary The Empire District Gas Company) and water service in Missouri, Kansas, Oklahoma and Arkansas. As part of Empire's electric segment, they also provide water service to three towns in Missouri. The Empire District Gas Company ("EDG"), a wholly-owned subsidiary of Empire, engages in the distribution of natural gas in Missouri. The determination of earnings is based on regulated rates of return that are applied to rate bases and does not change with a change of ownership. "Rate bases" includes jurisdictional rate base, in some cases assets earning a return through clauses and riders.

The excess of the estimated net purchase price of the Acquisition, before assumed debt and acquisition costs, over the assumed fair value of net assets acquired from Empire is classified as goodwill on the accompanying unaudited pro forma consolidated balance sheet.

(c) Common Share Issuance

Assumed financing for the Acquisition contemplates the issuance, through the exercise of conversion rights under the Debentures, of approximately 94.3 million APUC common shares at $10.60 per share for gross proceeds of approximately $1 billion.

Underwriting costs are estimated at 4% of gross proceeds in the aggregate or approximately $40 million and will result in a corresponding deferred income tax asset of approximately $11 million based on APUC's Canadian statutory income tax rate of 26.50%.

Interest costs associated with the Debentures at 5% are expected at a minimum to be $50 million for a 12 month period prior to closing and will result in a corresponding deferred income tax asset of approximately $13 million based on APUC's Canadian statutory income tax rate of 26.50%. These unaudited pro forma consolidated financial statements assume that the Debentures will be issued and immediately fully converted into APUC common shares at the assumed closing date of the Acquisition. As this incremental interest is directly related to the acquisition and is not-recurring, the accompanying unaudited pro forma consolidated statements of operations do not include interest costs associated with the Debentures. However, the estimated interest costs for the 12 month period and the related tax effect have been reflected as a pro forma adjustment to deficit in the unaudited pro forma consolidated balance sheet.

(d) Acquisition Credit Facility

For the purpose of this pro forma, the Acquisition assumes a drawdown of the Acquisition Credit Facility in the amount of $1.1 billion. Although the Company has shown the Acquisition Credit Facility drawn in such amount at closing, APUC currently expects that it will refinance the Acquisition Credit Facility before or after closing from one or more capital market offerings of common or preferred equity, convertible debentures and long-term debt. As a result the assumed utilization of the Acquisition Credit Facility is not representative of the financing structure or financing costs expected to be in place following closing of the Acquisition.

The interest rate is estimated at 1.9%, which would result in incremental interest expense for the year ended December 31, 2014 and for the nine months ended September 30, 2015 of $20 million and $15 million, respectively. Incremental interest expense would result in corresponding deferred income tax benefits of $8 million and $6 million, respectively, based on APUC's US statutory income tax rate of 38%.

Estimated Acquisition Credit Facility related costs of approximately $13 million have been included as a pro forma adjustment to deficit as opposed to being reflected in the unaudited pro forma consolidated statements of earnings of the Company on the basis that these expenses are directly incremental to the Acquisition of Empire and are non-recurring in nature.

(e) Acquisition costs

Acquisition costs are estimated at approximately $34 million. Acquisition costs are composed of estimated investment banking, accounting, tax, legal and other costs associated with the completion of the Acquisition. These costs have been included as a pro forma adjustment to deficit on the unaudited pro forma consolidated balance sheet. These costs are not reflected in the unaudited pro forma consolidated statements of operations on the basis that these expenses are directly incremental to the Acquisition of Empire and are non-recurring in nature.

(f) Income taxes

Income taxes applicable to the pro forma adjustments are calculated at APUC's average tax rates of 26.50% (for items with tax effect in the Canadian entities) and 38% (for items in the US entities).

The deferred income tax asset and liability is the cumulative amount of tax applicable to temporary differences between the accounting and tax values of assets and liabilities. Deferred income tax assets and liabilities are measured at enacted tax rates expected to apply when these differences are expected to reverse.

(g) Empire historical shareholders' equity

The historical shareholders' equity of Empire, which includes common shares, additional paid-in capital and retained earnings, has been eliminated in the unaudited pro forma balance sheet.

(h) Earnings per common share

The calculation of the pro forma earnings per common share for the year ended December 31, 2014 and for the nine months ended September 30, 2015 reflects the issuance of approximately 94.3 million APUC common shares upon the conversion of the Debentures which is assumed to take place on closing of the Acquisition, as if the issuance had taken place on January 1, 2014.

(i) Foreign exchange translation

The assets and liabilities of Empire, which has a US dollar functional currency, and reporting currency, are translated to APUC's Canadian dollar reporting currency at the exchange rate in effect as at September 30, 2015. Revenues and expenses of Empire's operations are translated at the average exchange rate in effect during the respective reporting periods. The following exchange rates were utilized for the unaudited pro forma consolidated financial statements:

Balance Sheet (US$ to Cdn$)

Spot Rate September 30, 2015: 1.3345

Statement of Operations (US$ to Cdn$)

Average Rate Year ended December 31, 2014	1.1045
Average Rate Nine months ended September 30, 2015	1.2600

	Twelve months ended December 31, 2014			Twelve months ended December 31, 2013		
	Windsor Locks	Sanger	Total	Windsor Locks	Sanger	Total
Performance(GW-hrs sold)	112.4	134.2	246.6	115.3	137.4	252.7
Performance(steam sales – billion lbs)	609.1	—	609.1	623.0	—	623.0
(all dollar amounts in $ millions)						
Revenue						
Energy/steam sales	$ 23.1	$ 19.8	$ 42.9	$ 17.6	$ 16.9	$ 34.5
Less:						
Cost of Sales – Fuel	(15.1)	(7.5)	$ (22.6)	(11.2)	(6.0)	(17.2)
Net Energy/Steam Sales	$ 8.0	$ 12.3	$ 20.3	$ 6.4	$ 10.9	$ 17.3
Other revenue	1.3	1.9	3.2	0.5	1.9	2.4
Total net revenue	$ 9.3	$ 14.2	$ 23.5	$ 6.9	$ 12.8	$ 19.7
Expenses						
Operating expenses	(4.4)	(5.0)	(9.4)	(3.7)	(4.8)	(8.5)
Facility operating profit	$ 4.9	$ 9.2	$ 14.1	$ 3.2	$ 8.0	$ 11.2
Interest and other income (loss)			$ (0.5)			$ 0.2
Divisional operating profit			13.6			11.4

2014 Twelve Month Operating Results

The Generation Group's Sanger and Windsor Locks Thermal Facilities purchase natural gas from different suppliers and at prices based on different regional hubs. As a result, the average landed cost per unit of natural gas will differ between the two facilities in the average landed cost for natural gas and may result in the facilities showing differing costs per unit compared to each other and compared to the same period in the prior year. Total natural gas expense will vary based on the volume of natural gas consumed and the average landed cost of natural gas for each MMBTU.

Production data, revenue and expenses have been adjusted to remove the results of the EFW and BCI Thermal Facilities, which were divested on April 4, 2014 for proceeds approximating the carrying value of the net assets on the Consolidated Balance Sheet of the Company as at March 31, 2014. The results of the EFW and BCI Thermal Facilities for the period up to the date of sale are reported as discontinued operations. See Financial Statement note 17 for details.

For the twelve months ended December 31, 2014, the Thermal Energy Division's operating profit was $13.6 million, as compared to $11.4 million in the same period in 2013, an increase of $2.2 million. The Windsor Locks Thermal Facility contributed $4.9 million, while the Sanger Thermal Facility contributed $9.2 million of operating profit during the twelve months ended December 31, 2014, as compared to $3.2 million and $8.0 million, respectively, during the same period in the prior year. Interest and other income for the twelve months ended December 31, 2014 was a loss of $0.5 million, as compared to income of $0.2 million during the same period in the prior year. As a result of the stronger U.S. dollar, operating profit was positively impacted by $1.1 million.

Windsor Locks Thermal Facility

For the twelve months ended December 31, 2014, the Windsor Locks Thermal Facility sold 609.1 billion lbs of steam and 112.4 GW-hrs of electricity, as compared to 623.0 billion lbs of steam and 115.3 GW-hrs of electricity in the comparable period of 2013.

The Windsor Locks Thermal Facility's operating profit was driven by energy/steam sales of $23.1 million (U.S. $20.9 million), as compared to $17.6 million (U.S. $17.1 million) in the same period in 2013. The increase in electricity/steam sales is attributed to a higher average price for gas as a result of the better ISO NE electricity market price driven by seasonally low temperatures in the first half of 2014. Gas costs for the period were $15.1 million (U.S. $13.7 million), as compared to

$11.2 million (U.S. $10.9 million) in the same period in 2013. The increase in gas costs is a result of increases in the average landed cost of natural gas per MMBTU in the first three quarters of the year, as compared to the same period in 2013.

As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales' (see non-GAAP Financial Measures) as an appropriate measure of the division's results. For the twelve months ended December 31, 2014, net energy/steam sales at the Windsor Locks Thermal Facility totalled $8.0 million (U.S. $7.2 million), as compared to $6.4 million (U.S. $6.2 million) during the same period in 2013, an increase of $1.6 million (U.S. $1.0 million).

Operating expenses excluding natural gas costs were $4.4 million (U.S. $4.0 million), as compared to $3.7 million (U.S. $3.6 million) during the same period in 2013. The increase is primarily attributable to a stronger U.S. dollar and the cost of RECs sold in the first nine months of 2014 but generated in 2013 (an offset to operating expense is booked when a REC is generated and is recorded as inventory). The Windsor Locks Thermal Facility's resulting net operating income for the twelve months ended December 31, 2014 was $4.9 million (U.S. $4.4 million), as compared to $3.2 million (U.S. $3.1 million) in the same period in 2013, an increase of $1.7 million; $0.4 million of the increase is attributable to the stronger U.S. dollar.

Sanger Thermal Facility

For the twelve months ended December 31, 2014, the Sanger Thermal Facility sold 134.2 GW-hrs of electricity, as compared to 137.4 GW-hrs of electricity in the comparable period of 2013. The decrease in production is due to the Sanger Thermal Facility's planned outage and limitation of run hours in the first quarter of 2014.

For the twelve months ended December 31, 2014, the Sanger Thermal Facility's operating profit was driven by energy/steam sales of $19.8 million (U.S. $17.9 million), as compared to $16.9 million (U.S. $16.4 million) in the same period in 2013, an increase of $2.9 million. The increase in energy/steam sales is attributed primarily to increased gas prices, as compared to 2013, which is a pass through to customers. Capacity revenues remained unchanged at $8.4 million. Gas costs for the period were $7.5 million (U.S. $6.8 million), as compared to $6.0 million (U.S. $5.8 million) in the same period in 2013. The increase in gas costs is largely due to a 19% increase in the average cost of natural gas per MMBTU and a stronger U.S. dollar, as compared to the same period in 2013.

As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales' (see non-GAAP Financial Measures) as an appropriate measure of the division's results. For the twelve months ended December 31, 2014, net energy sales at the Sanger Thermal Facility totalled $12.3 million (U.S. $11.1 million), as compared to $10.9 million (U.S. $10.6 million) during the same period in 2013, an increase of $1.4 million primarily due to more favorable pricing on the variable portion of the supply contract and an increase in the U.S. dollar exchange rate.

Operating expenses excluding natural gas costs were $5.0 million (U.S. $4.5 million), as compared to $4.8 million (U.S. $4.7 million) during the same period in 2013. The Sanger Thermal Facility's resulting net operating income for the twelve months ended December 31, 2014 was $9.2 million (U.S. $8.3 million), as compared to $8.0 million (U.S. $7.8 million) in the same period in 2013, an increase of $1.2 million; $0.7 million of the increase is attributable to the stronger U.S. dollar.

GENERATION BUSINESS GROUP

Development Division

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 Generation 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 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 Generation Group's Development Division will begin construction or execute an acquisition agreement.

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

Project Name	Location	Size (MW)		Estimated Capital Cost (millions)	Commercial Operation	PPA Term	Production GW-hrs
Projects Completed							
Cornwall Solar Facility[1]	Ontario	10	$	47.6	2014	20	14.4
St. Damase Wind Facility[1]	Quebec	24	$	69.7	2014	20	76.9
Total Completed		**34**	**$**	**117.3**			**91.3**
Projects in Construction							
Morse Wind Project[1]	Saskatchewan	23	$	81.3	2015	20	104.0
Bakersfield I Solar Project[1,2]	California	20	$	67.9	2015	20	53.3
Total Project in Construction		**43**	**$**	**149.2**			**157.3**
Projects in Development							
Odell Wind Project[1,3]	Minnesota	200	$	374.5	2015/16	20	814.7
Val Eo Wind Project[1,4,5]	Quebec	24	$	70.0	2016/17	20	66.0
Bakersfield II Solar Project[1,6]	California	10	$	31.3	2016	20	26.5
Amherst Island Wind Project[1]	Ontario	75	$	260.0	2016/17	20	235.0
Chaplin Wind Project[1,7]	Saskatchewan	177	$	340.0	2017/18	25	720.0
Total Projects in Development		**486**	**$**	**1,075.8**			**1,862.2**
Total in Construction and Development		**529**	**$**	**1,225.0**			**2,019.5**

1 PPA Signed.

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

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

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

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

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

7 The Chaplin project is being developed in two phases: Phase I of the project , which comprises approximately 35 MW of the total project, will be erected in 2017 and Phase II of the project, which comprises the remaining approximately 142 MW, will be constructed following evaluation of the wind resource at the site, and completion of satisfactory permitting.

Projects Completed

Cornwall Solar Facility

Construction of the project is now complete and commercial operation was achieved on March 27, 2014. The Cornwall Solar Facility is anticipated to have energy production of 14.4 GW-hrs/year. The Cornwall Solar Facility has been granted a 10 MW Feed In Tariff ("FIT") contract by the OPA, with a 20 year term and a rate of $443/MW-hr, resulting in expected initial annual revenues of approximately $6.2 million. Operating results from this project are now being reported in the Generation Group's renewable energy results.

St. Damase Wind Facility

Construction of the St. Damase Wind Facility is now complete and commercial operation was achieved on December 2, 2014. The facility has a 20 year PPA with Hydro Quebec. It is a 24 MW facility and is expected to generate $7.4 million in revenue in its first full year of operations.

It is expected that the turbines and other components utilized in the first 24 MW phase of the Saint-Damase Wind Facility will qualify as CRCE, and therefore a significant portion of the Phase I capital cost will be eligible for a refundable Quebec CRCE Tax Credit. In June 2014, the government of Quebec released the 2014-2015 budget, which included a 20% reduction in value for a wide range of tax credits, including the Quebec CRCE Tax Credit. The estimated value of the Quebec CRCE tax credit for the St. Damase project is expected to be approximately $16.6 million. Phase II of the project will be constructed following evaluation of the wind resource at the site, completion of satisfactory permitting, and entering into appropriate energy sales arrangements. Operating results from this project are now being reported in the Generation Group's renewable energy results.

Projects in Construction

Morse Wind Project

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

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

The Generation Group executed an asset purchase agreement with a local developer, Kineticor, to acquire assets related to two adjacent 10 MW wind energy development projects in Saskatchewan and a further 5 MW was developed by the Generation Group independently. All of the individual projects comprising the Morse wind project were selected by SaskPower in accordance with the SaskPower Green Options Partners Program.

The turbine supply agreements have been executed with Siemens and the Balance of Plant Engineering, Procurement and Construction agreement has been signed. The turbine placement has been finalized and registered land leases have been executed with the landowners. Installation of access roads and foundations are completed, and turbine delivery commenced in January 2015. Seven of ten turbine have been erected, and the project is expected to be operational by March 31, 2015.

Bakersfield I Solar Project

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

Construction of the project commenced in the second quarter of 2014 and was placed in service on December 30, 2014. Testing to ensure the plant will be ready and available for commercial operations was conducted and confirmed by the Generation Group and independent engineers. Final construction efforts continue, with the project expected to reach full commercial operation in the first quarter of 2015.

Projects in Development

Odell Wind Project

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

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

Val-Éo Wind Project

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

The Generation Group's equity interest in the project is subject to final negotiations with the Val-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.

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

Bakersfield II Solar Project

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

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

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

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

Amherst Island Wind Project

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

The Amherst Island Wind Project is currently contemplated to use Class III wind turbine generator technology. The available wind resource is forecast to produce approximately 235 GW-hrs of electrical energy annually, depending upon the final turbine selection for the project. Final negotiations on the turbine supply agreement is ongoing. Total capital costs for the facility are currently estimated to be $260 million, and engineering, procurement and construction contractor selection is underway. The financing of the project will be arranged and announced when all required permitting and all other pre-construction conditions have been satisfied.

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

Chaplin Wind Project

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

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

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

In March 2014, after review of the Project Proposal Environmental Assessment and Supplemental documentation (including the preliminary proposed layout), the project was deemed a development by the Environmental Assessment Branch. An additional detailed environmental review is currently being completed. It is anticipated that the Environmental Assessment documentation will be submitted to the government in the first quarter of 2015. The expected capital costs of the project are approximately $340 million. The Generation Group anticipates entering into a partnership and development agreement using a similar structure to what was utilized in the development of the Red Lily I Facility, in order to facilitate the development of the project and to optimize returns.

Ontario RFP Qualification

The Generation Group has qualified for participation in the anticipated 2015 Large Renewable Procurement I process with the IESO. The Generation Group may submit offers into the expected RFP for up to 100 MW of solar power and up to 100 MW of wind power. The IESO is expected to award up to 140 MW of solar projects and 300 MW of wind projects. RFP bids are due on September 1, 2015, with successful bidders being announced in December 2015.

DISTRIBUTION BUSINESS GROUP

The Distribution Group operates rate-regulated utilities providing distribution services to approximately 488,000 connections in the natural gas, electric, water and wastewater sectors. The Distribution Group's strategy is to grow its business organically and through business development activities while using prudent acquisition criteria. The Distribution Group believes that its business results are maximized by building constructive regulatory and customer relationships, and enhancing community connections.

Utility System Type	December 31, 2014		December 31, 2013	
(all dollar amounts in U.S. $ millions)	**Assets**	**Connections**	**Assets**	**Connections**
Electricity	**$ 325.0**	**93,000**	$ 276.6	92,000
Natural Gas	**726.0**	**292,000**	661.5	292,000
Water and Wastewater	**261.2**	**103,000**	233.0	97,400
Total	**$ 1,312.2**	**488,000**	$ 1,171.1	481,400
Accumulated Deferred Income Taxes	**$ 79.6**		$ 66.5	

The Distribution Group aggregates the performance of its utility operations by utility system type – electricity, natural gas, and water and wastewater systems.

The electric distribution systems are comprised of regulated electrical distribution utility systems and serve approximately 93,000 connections in the states of California and New Hampshire.

The natural gas distribution systems are comprised of regulated natural gas distribution utility systems and serve approximately 292,000 connections located in the states of New Hampshire, Illinois, Iowa, Missouri, Georgia, and Massachusetts.

The water and wastewater distribution systems are comprised of regulated water distribution and wastewater collection utility systems and serve approximately 103,000 connections located in the states of Arkansas, Arizona, Texas, Illinois, and Missouri.

		Three months ended December 31,		Three months ended December 31,	
		2014 U.S. $ (millions)	2013 U.S. $ (millions)	2014 Can $ (millions)	2013 Can $ (millions)
Revenue					
Utility electricity sales and distribution		**47.8**	41.9	**54.4**	46.4
Less: Cost of Sales – Electricity		**(29.9)**	(25.2)	**(34.2)**	(26.5)
Net Utility Sales - Electricity		**$ 17.9**	$ 16.7	**$ 20.2**	$ 19.9
Utility natural gas sales and distribution		**102.5**	83.5	**116.8**	88.0
Less: Cost of Sales – Natural Gas		**(65.6)**	(54.1)	**(74.9)**	(57.1)
Net Utility Sales - Natural Gas		**$ 36.9**	$ 29.4	**$ 41.9**	$ 30.9
Net Utility Sales - Water Distribution & Wastewater Treatment		**15.0**	14.0	**18.6**	14.6
Gas Transportation		**6.8**	4.5	**7.7**	4.7
Other Revenue		**3.0**	1.2	**3.5**	1.3
Net Utility Sales		**$ 79.6**	$ 65.8	**$ 91.9**	$ 71.4
Operating expenses		**(39.7)**	(34.0)	**(46.2)**	(35.6)
Other income		**0.8**	0.7	**0.9**	0.6
Distribution Group operating profit		**$ 40.7**	$ 32.5	**$ 46.6**	$ 36.4

2014 Fourth Quarter Operating Results

For the three months ended December 31, 2014, the Distribution Group reported an operating profit of U.S. $40.7 million, as compared to U.S. $32.5 million for the comparable period in the prior year. The increase is primarily due to implementation of higher rates at the Granite State Electric and Peach State Gas Systems and the acquisition of the New England Gas System on December 20, 2013. Detailed results are discussed in the following sections. Measured in Canadian dollars, the group's operating profit was $46.6 million, as compared to $36.4 million for the comparable period in the prior year. In addition to the factors described below, operating profit measured in Canadian dollars increased by $5.9 million due to a stronger U.S. dollar.

Electric Distribution Systems

	Three months ended December 31 2014	2013
Average Active Electric Connections For The Period		
Residential	**80,000**	78,000
Commercial and Industrial	**12,000**	12,000
Total Average Active Electric Connections For The Period	**92,000**	90,000
Customer Usage (GW-hrs)		
Residential	**134.9**	146.4
Commercial and Industrial	**230.5**	222.5
Total Customer Usage (GW-hrs)	**365.4**	368.9

For the three months ended December 31, 2014 the electric distribution systems' usage totalled 365.4 GW-hrs, as compared to 368.9 GW-hrs for the same period in 2013, a decrease of 3.5 GW-hrs. The decrease in residential usage can be primarily attributed to a lower number of heating degree days experienced at the CalPeco Electric System's service territory. A heating degree day is generally defined as the number of degrees that a day's average temperature is below 65 degrees Fahrenheit (18 degrees Celsius).

For the three months ended December 31, 2014, the electric distribution systems' revenue from utility electricity sales totalled U.S. $47.8 million, as compared to U.S. $41.9 million during the same period in 2013, an increase of U.S.$5.9 million, or 14.1%. For the three months ended December 31, 2014, fuel and purchased power costs for the electric distribution systems totalled U.S. $29.9 million, as compared to U.S. $25.2 million during the same period in 2013, an increase of U.S. 4.7 million, or 18.7%.

The purchase of electricity by the electric distribution systems is a significant revenue driver and component of operating expenses, however these costs are effectively passed through to its customers. As a result, 'net utility sales' (see non-GAAP Financial Measures) are a more appropriate measure of the results. For the three months ended December 31, 2014, net utility sales for the electric distribution systems were U.S. $17.9 million, as compared to U.S. $16.7 million during the same period in 2013, an increase of U.S. $1.2 million, or 7%. The increase in net utility sales is primarily attributed to increased rates at the Granite State Electric System as a result of finalization of the general rate case in March 2014. Under the base rate revenue decoupling mechanism approved by the CPUC, which became effective on January 1, 2013, the CalPeco Electric System's base rate revenues are not impacted by fluctuations in customer demand due to the variations in the weather conditions and changes in the number of customers. Instead, the CalPeco Electric System is required to record 1/12 of its annual base rate revenue requirement each month. The electricity commodity continues to be passed through to the CalPeco Electric System's customers according to their consumption.

Natural Gas Distribution Systems

	Three months ended December 31, 2014	2013
Average Active Natural Gas Connections For The Period		
Residential	**248,000**	217,000
Commercial and Industrial	**27,000**	24,000
Total Average Active Natural Gas Connections For The Period	**275,000**	241,000
Customer Usage (MMBTU)		
Residential	**3,918,000**	3,376,000
Commercial and Industrial	**2,885,000**	2,779,000
Total Customer Usage (MMBTU)	**6,803,000**	6,155,000

For the three months ended December 31, 2014, usage at the natural gas distribution systems totalled 6,803,000 MMBTU, as compared to 6,155,000 MMBTU during the same period in 2013, an increase of 648,000 MMBTU, or 10.5%. The increase in natural gas usage, as compared to the same period in 2013, can primarily be attributed to the acquisition of the

New England Gas System on December 20, 2013, at which usage totalled 1,053,000 MMBTU, and a higher number of heating degree days experienced in the Peach State Gas System's service territory. The increase was partially offset by a lower number of heating degree days experienced in the EnergyNorth Gas System and the Midstates Gas Systems service territories, as compared to the same period in 2013.

For the three months ended December 31, 2014, revenue excluding transportation revenue from natural gas sales and distribution totalled U.S. $102.5 million, as compared to U.S. $83.5 million during the same period in 2013, an increase of U.S. $19.0 million or 22.8%. For the three months ended December 31, 2014, natural gas purchases totalled U.S. $65.6 million, as compared with U.S. $54.1 million for the same period in 2013, an increase of U.S. $11.5 million or 21.3%. The cost of natural gas is passed through to the natural gas systems' customers. As a result, 'net utility sales' (see non-GAAP Financial Measures) are a more appropriate measure of the results. For the three months ended December 31, 2014, net utility sales for the natural gas distribution systems, excluding transportation, totalled U.S. $36.9 million, as compared to U.S. $29.4 million during the same period in 2013, an increase of U.S. $7.5 million, or 25.5%. The increase in net utility sales can be primarily attributed to the acquisition of the New England Gas System on December 20, 2013, which contributed U.S. $4.3 million of the total increase, and a U.S. $3.1 million increase at the Peach State Gas System primarily due to increased rates as a result of the GRAM filing.

For the three months ended December 31, 2014, revenue from gas transportation sales totalled U.S. $6.8 million, as compared to U.S. $4.5 million during the same period in 2013, an increase of U.S. $2.3 million. The increase in gas transportation sales can be primarily attributed to the acquisition of the New England Gas System on December 20, 2013, which contributed U.S. $1.2 million of the total increase, and a U.S. $1.0 million increase at the EnergyNorth Gas System, primarily due to increased customer demand.

Water and Wastewater Distribution Systems

	Three months ended December 31,	
	2014	**2013**
Average Active Connections For The Period		
Wastewater connections	**40,000**	36,900
Water distribution connections	**58,000**	55,900
Total Average Active Connections For The Period	**98,000**	92,800
Gallons Provided		
Wastewater treated (millions of gallons)	**535**	507
Water sold (millions of gallons)	**1,940**	2,080
Total Gallons Provided	**2,475**	2,587

During the three months ended December 31, 2014, the water and wastewater distribution systems provided approximately 1,940 million gallons of water to its customers and treated approximately 535 million gallons of wastewater, as compared to 2,080 million gallons of water and 507 million gallons of wastewater during the same period in 2013. The decrease in the gallons of water provided to customers can be attributed to increased precipitation, primarily in the state of Arizona during the three months ended December 31, 2014, as compared to the comparable period in the prior year.

The increase in average active wastewater and water distribution connections can be primarily attributed to the acquisition of the White Hall Water System on May 30, 2014.

For the three months ended December 31, 2014, revenue from wastewater treatment and water distribution totalled U.S. $6.9 million and U.S. $8.1 million, respectively, as compared to U.S. $6.1 million and U.S. $7.9 million, respectively, during the same period in 2013. The increase in wastewater treatment and water distribution revenue was primarily due to an increase in rates at the LPSCo Water and Sewer System, effective May 1, 2014, and the acquisition of the White Hall Water System on May 30, 2014.

Other Revenue

For the three months ended December 31, 2014, other revenue totalled U.S. $3.0 million, as compared to $1.2 million during the same period in 2014. The other revenue consists of water heater rental service and a contract to supply gas to Fort Benning.

Operating Expenses

For the three months ended December 31, 2014, operating expenses, excluding electricity purchases, totalled U.S. $39.7 million, as compared to U.S. $34.0 million during the same period in 2013, an increase of U.S. $5.7 million, or 17%. The major factors resulting in the increase in the Distribution Group's operating expenses in the three months ended December 31, 2014, as compared to the corresponding period in 2013, are set out as follows:

(all dollar amounts in U.S. $ millions)	Quarter ended December 31, 2014	
Comparative Prior Period Operating Expenses	$	34.0
Significant Changes:		
Acquisition of New England Gas System		6.3
Decrease in operating expenses at Granite State Electric Utility and EnergyNorth Gas Utility		(1.4)
Acquisition of White Hall Water System		0.2
Increase in operating expenses at CalPeco Electric System		0.2
Other		0.4
Current Period Operating Expenses	$	39.7

	Twelve months ended December 31,				Twelve months ended December 31,			
		2014 U.S. $ (millions)		2013 U.S. $ (millions)		**2014 Can $ (millions)**		2013 Can $ (millions)
Revenue								
Utility electricity sales and distribution		**186.8**		161.3		**206.7**		166.2
Less: Cost of Sales – Electricity		**(108.8)**		(94.5)		**(120.5)**		(97.4)
Net Utility Sales - Electricity	**$**	**78.0**	$	66.8	**$**	**86.2**	$	68.8
Utility natural gas sales and distribution		**378.2**		236.0		**419.9**		243.1
Less: Cost of Sales – Natural Gas		**(234.8)**		(144.5)		**(261.1)**		(148.8)
Net Utility Sales - Natural Gas	**$**	**143.4**	$	91.5	**$**	**158.8**	$	94.3
Net Utility Sales - Water Distribution & Wastewater Treatment		**58.7**		55.6		**66.4**		57.4
Gas Transportation		**23.5**		16.8		**26.1**		17.3
Other Revenue		**5.1**		1.2		**5.7**		1.3
Net Utility Sales	**$**	**308.7**	$	231.9	**$**	**343.2**	$	239.1
Operating expenses		**(162.7)**		(127.5)		**(180.4)**		(131.6)
Other income		**3.0**		3.1		**3.4**		3.2
Distribution Group operating profit	**$**	**149.0**	**$**	**107.5**	**$**	**166.2**	$	110.7

2014 Twelve Month Operating Results

For the twelve months ended December 31, 2014, the Distribution Group reported an operating profit of U.S. $149.0 million, as compared to U.S. $107.5 million for the comparable period in the prior year. The increase is primarily due to the acquisition of the New England Gas System on December 20, 2013, the acquisition of the Peach State Gas System on April 1, 2013, and higher rates at the Granite State Electric System. Detailed results are discussed in the following sections. Measured in Canadian dollars, the group's operating profit was $166.2 million, as compared to $110.7 million for the comparable period in the prior year. In addition to the factors discussed below, operating profit measured in Canadian dollars increased by $17.2 million due to a stronger U.S. dollar.

Electric Distribution Systems	Twelve months ended December 31,	
	2014	2013
Average Active Electric Connections For The Period		
Residential	**79,000**	78,000
Commercial and Industrial	**12,000**	12,000
Total Average Active Electric Connections For The Period	**91,000**	90,000
Customer Usage (GW-hrs)		
Residential	**557.4**	585.9
Commercial and Industrial	**933.4**	905.5
Total Customer Usage (GW-hrs)	**1,490.8**	1,491.4

For the twelve months ended December 31, 2014, the electric distribution systems' usage totalled 1,490.8 GW-hrs, as compared to 1,491.4 GW-hrs for the same period in 2013. The decrease in residential usage can be primarily attributed to a lower number of heating degree days experienced at the CalPeco Electric System's service territory.

For the twelve months ended December 31, 2014, the electric distribution systems revenue from utility electricity sales totalled U.S. $186.8 million, as compared to U.S. $161.3 million during the same period in 2013, an increase of U.S. $25.5 million, or 15.8%. For the twelve months ended December 31, 2014, fuel and purchased power costs for the electric distribution systems totalled U.S $108.8 million, as compared to U.S. $94.5 million for the same period in 2013, an increase of U.S. $14.3 million, or 15.1%.

The purchase of electricity by the electric distribution systems is a significant revenue driver and component of operating expenses, but these costs are effectively passed through to its customers. As a result, 'net utility sales' (see non-GAAP Financial Measures) are a more appropriate measure of the results. For the twelve months ended December 31, 2014, net utility sales for the electric distribution systems were U.S. $78.0 million, as compared to U.S. $66.8 million for the same period in 2013, an increase of U.S. $11.2 million, or 16.8%. The increase in net utility sales can be primarily attributed to an increase in distribution rates to customers from finalization of the Granite State Electric System's general rate case, as well as U.S. $2.5 million in additional revenue recognized in the first quarter of 2014, which represented the difference from the interim rates previously granted to the Granite State Electric System and the final rates retroactive to July 1, 2013. Under the base rate revenue decoupling mechanism approved by the CPUC, which became effective on January 1, 2013, the CalPeco Electric System's base rate revenues are not impacted by fluctuations in customer demand due to the variations in the weather conditions and changes in the number of customers. Instead, the CalPeco Electric System is required to record 1/12 of its annual base rate revenue requirement each month. The electricity commodity continues to be passed through to the CalPeco Electric System's customers according to their consumption.

Natural Gas Distribution Systems

	Twelve months ended December 31, 2014	2013
Average Active Natural Gas Connections For The Period		
Residential	**248,000**	204,000
Commercial and Industrial	**26,000**	23,000
Total Average Active Natural Gas Connections For The Period	**274,000**	227,000
Customer Usage (MMBTU)		
Residential	**18,915,000**	12,401,000
Commercial and Industrial	**12,673,000**	8,706,000
Total Customer Usage (MMBTU)	**31,588,000**	21,107,000

For the twelve months ended December 31, 2014, customer usage at the natural gas distribution systems totalled 31,588,000 MMBTU, as compared to 21,107,000 MMBTU during the same period in 2013, an increase of 10,481,000 MMBTU, or 49.7%. The increase in natural gas usage, as compared to the same period in 2013, can be primarily attributed to the acquisitions of the Peach State Gas System on April 1, 2013 and the New England Gas System on December 20, 2013; the New England Gas System usage totalled 5,273,000 MMBTU.

For the twelve months ended December 31, 2014, revenue from natural gas sales and distribution totalled U.S. $378.2 million, as compared to U.S. $236.0 million during the same period in 2013, an increase of U.S. $142.2 million. For the twelve months ended December 31, 2014, natural gas purchases totalled U.S. $234.8 million, as compared to U.S. $144.5 million for the same period in 2013, an increase of U.S. $90.3 million. The cost of natural gas is passed through to the natural gas distribution systems' customers. As a result, 'net utility sales' (see non-GAAP Financial Measures) are a more appropriate measure of results. For the twelve months ended December 31, 2014, net utility sales, excluding transportation, for the natural gas distribution systems totalled U.S. $143.4 million, as compared to U.S. $91.5 million during the same period in 2013, an increase of U.S. $51.9 million, or 57%. The increase is attributed as follows: U.S. $30.5 million increase from the New England Gas System, which was acquired on December 20, 2013; U.S. $4.5 million increase from the EnergyNorth Gas System, primarily due to the colder winter weather experienced during the first quarter of 2014, as compared to the first quarter of 2013; U.S. $15.1 million increase from the Peach State Gas System; primarily attributed to the inclusion of twelve months of operating results in 2014, as compared to nine months in 2013; increased rates as a result of the GRAM filing at the Peach State Gas System; and a U.S. $1.8 million increase from the Midstates Gas Systems due to the colder winter weather experienced during the first quarter of 2014, as compared to the first quarter of 2013.

For the twelve months ended December 31, 2014, revenue from gas transportation sales totalled U.S. $23.5 million, as compared to U.S. $16.8 million during the same period in 2013, an increase of U.S. $6.7 million. The increase in gas transportation sales can be primarily attributed to the acquisition of the New England Gas System on December 20, 2013, which contributed U.S. $6.1 million of the total increase.

Water and Wastewater Distribution Systems

	Twelve months ended December 31, 2014	2013
Average Active Connections For The Period		
Wastewater connections	**39,000**	36,600
Water distribution connections	**58,000**	55,800
Total Average Active Connections For The Period	**97,000**	92,400
Gallons Provided		
Wastewater treated (millions of gallons)	**2,127**	2,034
Water sold (millions of gallons)	**8,310**	8,162
Total Gallons Provided	**10,437**	10,196

Average active wastewater and water distribution connections increased primarily due to the acquisition of the White Hall Water and Sewer System on May 30, 2014.

During the twelve months ended December 31, 2014, the water and wastewater distribution systems provided approximately 8,310 million gallons of water to its customers and treated approximately 2,127 million gallons of wastewater, as compared to 8,162 million gallons of water and 2,034 million gallons of wastewater during the same period in 2013. The increase in water sold can be primarily attributed to the acquisition of the White Hall Water System on May 30, 2014, and an additional month of operations from the Pine Bluff Water System in the first twelve months of 2014, as compared to the first twelve months of 2013. The increase in wastewater treated is primarily attributed to an increase in wastewater treated at our sewer utilities located in the state of Arizona.

For the twelve months ended December 31, 2014, revenue from wastewater treatment and water distribution totalled U.S. $26.1 million and U.S. $32.6 million, respectively, as compared to U.S. $24.3 million and U.S. $31.3 million, respectively, during the same period in 2013. Increased rates at the LPSCo Water and Sewer System, effective May 1, 2013, Rio Rico Water System, effective August 1, 2013, and Woodmark Waste System, effective October 1, 2013, are the primary drivers of the increase along with the acquisition of the White Hall Water System on May 30, 2014.

Other Revenue

For the twelve months ended December 31, 2014, other revenue totalled U.S. $5.1 million, as compared to U.S. $1.2 million during the same period in 2014. The other revenue consists of water heater rental service and a contract to supply gas to Fort Benning.

Operating Expenses

For the twelve months ended December 31, 2014, operating expenses, excluding electricity purchases, totalled U.S. $162.7 million, as compared to U.S. $127.5 million during the same period in 2013, an increase of U.S. $35.2 million, or 28%. The major factors resulting in the increase in DBG operating expenses in the twelve months ended December 31, 2014, as compared to the corresponding period in 2013, are set out as follows:

(all dollar amounts in U.S. $ millions)	Year to date December 31, 2014
Comparative Prior Period Operating Expenses	$ 127.5
Significant Changes:	
Acquisition of New England Gas System	26.3
Increase in operating expenses at the Granite State Electric System and EnergyNorth Gas System	4.6
Increase in operating expenses at the Peach State Gas System	2.2
Increase in operating expenses at the Midstates Gas Systems	0.8
Acquisition of White Hall Water System	0.5
Other	0.8
Current Period Operating Expenses	$ 162.7

The primary reason for the increase in operating expenses for the twelve months ended December 31, 2014, as compared to the corresponding period in 2013, was the acquisition of the New England Gas System on December 20, 2013. The full year of operating expenses, as compared to eleven days of operating expenses in 2013, contributed an additional U.S. $26.3 million.

Operating expenses at the Granite State Electric and EnergyNorth Gas Systems were U.S. $4.6 million higher than the prior fiscal year, primarily due to increased bad debt expense in the first nine months of the year, a property tax assessment related to a prior assessment year, and additional work for leak repairs.

The increase in operating expenses at the Peach State Gas System of U.S. $2.2 million was primarily due to twelve months of operation during the twelve months ended December 31, 2014, as compared to nine months of operation during the nine months ended December 31, 2013. The Peach State Gas System was acquired on April 1, 2013.

The increase in operating expenses at the Midstates Gas Systems of U.S. $0.8 million can be primarily attributed due to increased costs for billings services and communication expenses.

The acquisition of the White Hall Water System on May 30, 2014 resulted in an increase in operating expenses of U.S. $0.5 million during the twelve months ended December 31, 2014.

Regulatory Proceedings

The following table summarizes the major regulatory proceedings within the Distribution Group currently underway:

Utility	State	Regulatory Proceeding Type	Rate Request U.S. $ (millions)	Current Status
Completed Rate Cases				
Granite State Electric System	New Hampshire	General Rate Case	$13,000	Final Order issued on March 2014 approving a $9.8 million rate increase effective April 1, 2014.
Granite State Electric System	New Hampshire	General Rate Case - Step Adjustment	$1,200	Final Order issued on March 2014 approving a $1.1 million in step increase for 2014 effective April 1, 2014
Peach State Gas System	Georgia	GRAM	$4,900	Final Order issued on May 2014 approving a $3.2 million rate increase retroactive to February 1, 2014, and the recovery of $1.7 million of carrying charges on deferred rate base in a future GRAM filing.
Peach State Gas System	Georgia	GRAM	$3,900	Final Order issued on December 2014 approving a $3.7 million rate increase effective February 1, 2015.
LPSCo Water System	Arizona	General Rate Case	$3,000	Final Order issued on April 2014 approving a $1.8 million rate increase effective May 1, 2014.
Missouri Gas System	Missouri	General Rate Case	$7,600	Final Order issued on December 2014 approving a $4.9 million rate increase effective January 2, 2015.
Illinois Gas System	Illinois	General Rate Case	$5,700	Final Order issued on February 11, 2015 approving a $4.6 million revenue increase effective February 20, 2015.
Pending Rate Cases				
Pine Bluff Water System	Arkansas	General Rate Case	$2,500	Application was filed on July 2, 2014; Order expected in Q2 2015
EnergyNorth System	New Hampshire	General Rate Case	$16,100	Application filed on August 1, 2014; a temporary rate increase was approved on November 21, 2014 allowing a $7.4M interim increase effective December 1, 2014, retroactive to November 1, 2014 upon approval of permanent rates. A final permanent rates decision is expected in Q3 2015.

Completed Rate Cases

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

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

On October 1, 2014, the Peach State Gas System filed an application for an increase in revenue of U.S. $3.9 million in its annual GRAM filing with the GPSC. New rates to be effective February 1, 2015 for the period February 1, 2015, through January 31, 2016 were to reflect changes in revenue levels and cost of service. The GRAM uses a 12 month base period ending June 30, 2014 (Historic Test Year) with adjustments for the 12 months ending August 31, 2015 (Forward Looking Test Year). Commission approval was received on December 2, 2014.

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

On February 6, 2014, the Midstates Gas System filed a rate case with the Missouri Public Service Commission ("MOPSC") seeking an increase in revenue of U.S. $7.6 million, consisting of U.S. $6.3 million in new, incremental revenue and U.S. $1.3 million through the ISRS surcharge (infrastructure system replacement surcharge). The filing is based on a test year ending September 30, 2013, with revenues, expenses and rate bases adjusted to reflect known and measurable changes through April 30, 2014. The case has concluded and an Order was issued on December 3, 2014, approving a U.S. $4.9 million revenue increase effective January 2, 2015.

On March 31, 2014, the Midstates Gas System filed a rate case with the Illinois Commerce Commission ("ICC") seeking an increase in EBITDA of U.S. $5.7 million. The filing is 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.

Pending Rate Cases

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

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

Acquisition Approval Applications

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

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

Mountain Water Company is the water utility in Western Montana owned by Park Water Company which serves the municipality of Missoula. Mountain Water Company is currently the subject of a condemnation proceeding by the city of Missoula (See "Regulatory Risk").

TRANSMISSION BUSINESS GROUP

In 2014, APUC created the Transmission Group which the Company believes complements the growth of the Generation and Distribution Groups. The Transmission Group is responsible for identifying, evaluating, and capitalizing upon natural gas pipeline and electric transmission asset opportunities in North America.

For its first major project on November 24, 2014, the Transmission Group announced an agreement to participate in a natural gas pipeline transmission project in partnership with Kinder Morgan, Inc. Specifically, Kinder Morgan Operating L.P. "A," a wholly owned subsidiary of Kinder Morgan, Inc., and Liberty Utilities (Pipeline & Transmission) Corp., a wholly owned subsidiary of APUC, have agreed to form a new entity ("Northeast Expansion LLC") to undertake the development, construction and ownership of a 30-inch or 36-inch natural gas transmission pipeline to be located between Wright, NY and Dracut, MA (the "Project"), which will be operated by Tennessee Gas Pipeline Company, L.L.C. ("Tennessee"). The Project is scalable up to 2.2 billion cubic feet per day (Bcf/d), and the pipeline capacity will be contracted with local distribution utilities, and other customers, to help ease constraints on natural gas supply in the northeast U.S. and help ensure much needed reliability to the power-generation grid. It is anticipated that Tennessee will receive a FERC certificate in the fourth quarter of 2016, with construction anticipated to begin in January 2017 and commercial operations expected by Nov. 1, 2018.

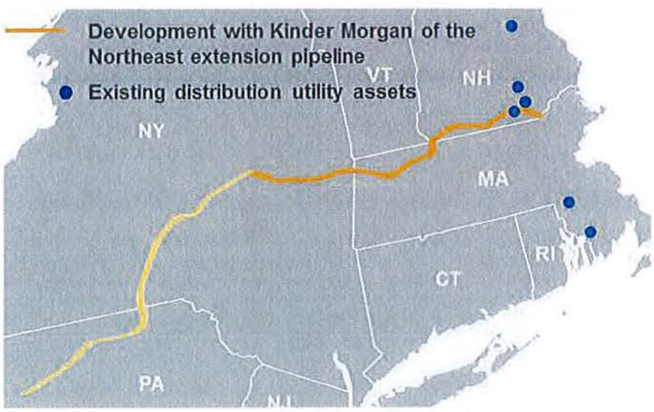
Under the agreement, APUC will initially subscribe for a 2.5% interest in Northeast Expansion LLC. APUC also has an opportunity to increase its participation up to 10%. The total capital investment opportunity for APUC could be up to U.S. $400 million, depending on the final pipeline configuration and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

The U.S. $3-$4 billion infrastructure project consists of 188 miles of pipeline and six new compressor stations to be constructed through the states of New York, Massachusetts and New Hampshire. The pipeline is designed to provide up to 2.2 Bcf/day of firm gas deliveries to gas distribution utilities, gas fired generation, industrial customers and other New England consumers. Given the proposed route of the project, the Distribution Group will also look to economically expand its gas distribution utility footprint in New Hampshire as well to serve over twenty new communities with natural gas service.

Under the current September 15, 2014 application before the FERC under Docket No. PF 14 - 22, the project sponsor has proposed the following development calendar of events for proceeding with the project:

1st Draft of the Environmental Review	March 6, 2015
2nd Draft of the Environmental Review	June 5, 2015
FERC Section 7 Certificate Application Filed	September, 2015
FERC Section 7 Certificate Approval Received	October 31, 2016
Targeted In- Service of Core NED Project	November 1, 2018

The project route has recently been modified to address a number of comments raised by various stakeholders and is shown as the orange solid line on the map below and has been filed with the FERC for further consideration.



Continued development of the project in 2015 will include ongoing environmental research, further outreach programs, development of procurement plans for long lead time items and continued marketing of available firm capacity prior to and following the September 2015 FERC application.

APUC: CORPORATE AND OTHER EXPENSES

APUC: CORPORATE AND OTHER EXPENSES	**Three months ended December 31,**		**Year ended December 31,**	
(all dollar amounts in $ millions)	**2014**	2013	**2014**	2013
Corporate and other expenses:				
Administrative expenses	**$ 10.5**	$ 5.2	**$ 34.7**	$ 23.5
(Gain)/Loss on foreign exchange	**0.3**	(0.1)	**(1.1)**	(0.6)
Interest expense	**14.1**	14.4	**62.4**	53.4
Interest, dividend and other Income[1]	**0.5**	0.7	**3.2**	2.5
Write down of long lived assets	**0.3**	—	**8.5**	—
Acquisition-related costs	**1.6**	0.6	**2.6**	2.1
(Gain)/Loss on derivative financial instruments	**2.0**	(2.7)	**1.4**	(5.2)
Income tax expense	**3.7**	5.2	**16.8**	9.2

1 Excludes income directly pertaining to the Generation and Distribution Groups (disclosed in the relevant sections).

2014 Annual Corporate and Other Expenses

During the year ended December 31, 2014, administrative expenses totalled $34.7 million, as compared to $23.5 million in the same period in 2013. The expense increase for the period is primarily due to approximately $6.3 million of expenses previously classified as direct operating expenses that have been reclassified in 2014 as administrative expenses as certain functions are now being performed centrally as part of a shared services function across the entire company. The remaining $4.9 million increase primarily relates to additional costs incurred to administer APUC's operations as a result of the company's growth.

For the year ended December 31, 2014, interest expense totalled $62.4 million, as compared to $53.4 million in the same period in 2013. The increased interest expense is a result of new indebtedness incurred during the first half of 2014 used to partially finance new acquisitions and fund other growth initiatives.

For the year ended December 31, 2014, interest, dividend and other income totalled $3.2 million, as compared to $2.5 million in the same period in 2013, an increase of $0.7 million due to an incremental $2.5 million in rental income earned in 2014, partially offset by $1.8 million in decreased dividends from APUC's share investment in the Kirkland and Cochrane Thermal Facilities.

For the year ended December 31, 2014, acquisition related costs totalled $2.6 million, as compared to $2.1 million in the same period in 2013. Acquisition related costs will vary from period to period depending on the level of activity and complexity associated with various acquisitions.

For the year ended December 31, 2014, loss on derivative financial instruments totalled $1.4 million, as compared to a gain of $5.2 million in the same period in 2013. The decrease was primarily driven by derivative losses on hedges to purchase electricity for resale at contracted rates that differ from the market rate.

An income tax expense of $16.8 million was recorded in the year ended December 31, 2014, as compared to an income tax expense of $9.2 million during the same period in 2013. The increase in income tax expense for the year ended December 31, 2014 is primarily due to increased earnings from operations, increased deferred taxes on HLBV income, a stronger U.S. dollar, and other items permanently non-deductible for tax purposes.

2014 Fourth Quarter Corporate and Other Expenses

During the quarter ended December 31, 2014, administrative expenses totalled $10.5 million, as compared to $5.2 million in the same period in 2013. The increase was primarily due to $3.9 million in additional costs incurred to administer APUC's operations as a result of the company's growth and $1.4 million of expenses previously classified as direct operating expenses that have been reclassified in 2014 as administrative expenses as certain functions are now being performed centrally as part of a shared services function across the entire company.

For the quarter ended December 31, 2014, interest expense totalled $14.1 million, as compared to $14.4 million in the same period in 2013. The decreased interest expense is a result of increased capitalization of interest expense due to the ongoing development projects during the end of period.

For the quarter ended December 31, 2014, interest, dividend and other income totalled $0.5 million, as compared to $0.7 million in the same period in 2013. Interest, dividend and other income primarily consists of $0.7 million in rental income, partially offset by $0.3 million in decreased dividends from APUC's share investment in the Kirkland and Cochrane Thermal Facilities.

For the quarter ended December 31, 2014, loss on derivative financial instruments totalled $2.0 million, as compared to a gain of $2.7 million in the same period in 2013. The decrease was primarily driven by derivative losses on hedges to purchase electricity for resale at contracted rates that differ from the market rate.

An income tax expense of $3.7 million was recorded in the three months ended December 31, 2014, as compared to an income tax expense of $5.2 million during the same period in 2013. The decrease in income tax expense for the quarter ended December 31, 2014 is primarily due to a reversal of an alternative minimum tax liability accrued in prior year, which is no longer a liability based on the amended legislation in the Internal Revenue Code, offset by increased earnings from operations, increased deferred taxes on HLBV income, and a stronger U.S. dollar.

NON-GAAP PERFORMANCE MEASURES

Reconciliation of Adjusted EBITDA to net earnings

The following table is derived from and should be read in conjunction with the audited Consolidated Statement of Operations. This supplementary disclosure is intended to more fully explain disclosures related to Adjusted EBITDA and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to GAAP consolidated net earnings.

	Three months ended December 31,		Year ended December 31,	
(all dollar amounts in $ millions)	2014	2013	2014	2013
Net earnings attributable to Shareholders	$ 31.6	$ 13.2	$ 75.7	$ 20.3
Add (deduct):				
Net earnings / (loss) attributable to the non-controlling interest, exclusive of HLBV	**0.5**	3.4	**5.0**	9.6
Loss from discontinued operations	**1.5**	6.7	**2.1**	42.0
Income tax expense	**3.7**	5.2	**16.8**	9.2
Interest expense	**14.1**	14.4	**62.4**	53.4
Loss / (Gain) on sale of assets	**(0.1)**	0.6	**(0.4)**	0.8
Non-cash write downs	**0.3**	—	**8.5**	—
Acquisition costs	**1.6**	0.6	**2.6**	2.1
(Gain) / Loss on derivative financial instruments	**2.0**	(2.7)	**1.4**	(5.2)
Realized gain / (loss) on energy derivative contracts	**(0.2)**	0.3	**3.6**	0.5
(Gain) / Loss on foreign exchange	**0.3**	(0.1)	**(1.1)**	(0.6)
Depreciation and amortization	**29.0**	26.9	**114.0**	96.0
Adjusted EBITDA	**$ 84.3**	$ 68.5	**$ 290.6**	$ 228.1

Hypothetical Liquidation at Book Value ("HLBV") represents the value of net tax attributes earned by the Generation Group in the period from electricity generated by certain of its U.S. wind power generation facilities. The value of net tax attributes earned in the three and twelve months ended December 31, 2014 amounted to approximately $8.9 million and $27.2 million, respectively.

For the year ended December 31, 2014, Adjusted EBITDA totalled $290.6 million, as compared to $228.1 million during the same period in 2013, an increase of $62.5 million. For the quarter ended December 31, 2014, Adjusted EBITDA totalled $84.3 million, as compared to $68.5 million, an increase of $15.8 million compared to the same period in 2013.

The major factors impacting Adjusted EBITDA are set out below. A more detailed analysis of these factors is presented within the business unit analysis.

(all dollar amounts in $ millions)	Quarter ended December 31, 2014	Year ended December 31, 2014
Comparative Prior Period Adjusted EBITDA	$ 68.5	$ 228.1
Significant Changes:		
Generation Business Group:		
Renewable		
Increase / (decreased) hydrology resource	2.2	(2.0)
Decreased/increased wind resources for the quarter/year to date, at the U.S. Wind Facilities offset by unfavorable periodic hedge settlements shortfalls at the Minonk, Sandy Ridge and Senate facilities	3.2	2.8
Higher realized prices on sale of Renewable Energy Credits at the U.S. Wind Facilities	1.1	4.9
Start of commercial operations for the Cornwall Solar Facility	0.3	4.8
Increased wind resources at the St Leon wind facilities	0.3	3.1
Unfavorable retail pricing at AES partially offset by gains from hedge settlements and increased customer load.	1.2	(1.8)
Thermal		
Increased market prices at the Sanger and Windsor Locks Thermal Facility	0.3	1.3
Higher realized prices on sale of Renewable Energy Credits	(0.1)	0.7
Distribution Business Group:		
Increased delivery and treatment of water and wastewater systems	0.7	3.2
Increased rates at the Granite State Electric System	1.4	10.2
Changes in customer demand and higher operating expenses at the EnergyNorth and the Midstates Gas Systems	1.8	1.9
2013 Acquisition of the New England and Peach State Gas Systems	2.5	23.6
Increase earnings due to acquisition of New England Gas System's water heater rental service and the Peach State Gas System's Fort Benning operation	1.8	3.8
Administrative expense	(5.4)	(11.2)
Increased results from the stronger U.S. dollar	6.6	18.4
Other	(2.1)	(1.2)
Current Period Adjusted EBITDA	$ 84.3	$ 290.6

Reconciliation of adjusted net earnings to net earnings

The following table is derived from and should be read in conjunction with the audited Consolidated Statement of Operations. This supplementary disclosure is intended to more fully explain disclosures related to adjusted net earnings and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to consolidated net earnings in accordance with GAAP.

The following table shows the reconciliation of net earnings to adjusted net earnings exclusive of these items:

	Three months ended December 31,		Year ended December 31,	
(all dollar amounts in $ millions)	**2014**	2013	**2014**	2013
Net earnings attributable to Shareholders	**$ 31.6**	$ 13.2	**$ 75.7**	$ 20.3
Add (deduct):				
(Gain) / Loss from discontinued operations, net of tax	**1.5**	6.7	**2.1**	42.0
(Gain) / Loss on derivative financial instruments, net of tax	**1.2**	(1.6)	**0.8**	(3.1)
Realized gain / (loss) on derivative financial instruments, net of tax	**(0.5)**	(0.2)	**0.7**	(1.2)
Write down long lived assets	**0.3**	—	**8.5**	—
(Gain) / Loss on asset disposal, net of tax	**(0.1)**	0.4	**(0.3)**	0.5
(Gain) / Loss on foreign exchange, net of tax	**0.2**	(0.1)	**(0.7)**	(0.3)
Acquisition costs, net of tax	**1.0**	0.4	**1.6**	1.3
Adjusted net earnings	**$ 35.2**	$ 18.8	**$ 88.4**	$ 59.5
Adjusted net earnings per share	**$ 0.14**	$ 0.08	**$ 0.37**	$ 0.26

For the year ended December 31, 2014, adjusted net earnings totalled $88.4 million, as compared to adjusted net earnings of $59.5 million, an increase of $28.9 million as compared to the same period in 2013. The increase in adjusted net earnings for the year ended December 31, 2014 is primarily due to higher income from operations partially offset by higher interest expense, and depreciation and amortization expense as compared to the same period in 2013.

For the three months ended December 31, 2014, adjusted net earnings totalled $35.2 million, as compared to adjusted net earnings of $18.8 million, an increase of $16.4 million as compared to the same period in 2013. The increase in adjusted net earnings for the three months ended December 31, 2014 is primarily due to increased earnings from operations partially offset by higher depreciation and amortization expense, and higher interest expense as compared to the same period in 2013.

Reconciliation of adjusted funds from operations to cash flows from operating activities

The following table is derived from and should be read in conjunction with the audited Consolidated Statement of Operations and Statement of Cash Flows. This supplementary disclosure is intended to more fully explain disclosures related to adjusted funds from operations and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to funds from operations in accordance with GAAP.

The following table shows the reconciliation of funds from operations to adjusted funds from operations exclusive of these items:

	Three months ended December 31,		Year ended December 31,	
(all dollar amounts in $ millions)	2014	2013	2014	2013
Cash flows from operating activities	**$ 96.5**	$ 28.4	**$ 192.7**	$ 98.9
Add (deduct):				
Changes in non-cash operating items	**(33.1)**	13.5	**0.5**	47.8
Cash (provided)/used in discontinued operation	**0.9**	3.5	**1.7**	4.4
Production Tax Credits received from non-controlling interests	**—**	—	**9.0**	1.7
Acquisition costs	**1.6**	0.6	**2.6**	2.1
Adjusted funds from operations	**$ 65.9**	$ 46.0	**$ 206.5**	$ 154.9
Adjusted funds from operations per share	**0.27**	0.22	**0.92**	0.73

For the year ended December 31, 2014, adjusted funds from operations totalled $206.5 million, as compared to adjusted funds from operations of $154.9 million, an increase of $51.6 million as compared to the same period in 2013.

For the three months ended December 31, 2014, adjusted funds from operations totalled $65.9 million, as compared to adjusted funds from operations of $46.0 million, an increase of $19.9 million as compared to the same period in 2013.

SUMMARY OF PROPERTY, PLANT, AND EQUIPMENT EXPENDITURES

	Three months ended December 31,		Year ended December 31,	
(all dollar amounts in $ millions)	2014	2013	2014	2013
GENERATION GROUP				
Renewable	**$ 59.6**	$ 18.0	**$ 197.1**	$ 46.9
Thermal	**0.5**	1.3	**4.0**	2.6
Total Generation Business Group	**$ 60.1**	$ 19.3	**$ 201.1**	$ 49.5
DISTRIBUTION GROUP	**$ 77.4**	$ 43.4	**$ 176.8**	$ 108.9
Corporate	**4.3**	—	**54.5**	—
Total	**$ 141.8**	$ 62.7	**$ 432.4**	$ 158.4

The company's consolidated capital expenditure plan for 2015 is approximately $261.0 million. The Generation Group expects to invest approximately $107.0 million primarily in connection with the development of its existing project pipeline. The Distribution Group expects to invest approximately $147.0 million primarily to improve the reliability and efficiency of its gas and electric utility distribution systems. The Transmission Group expects to invest approximately $7.0 million for the natural gas pipeline transmission project.

APUC anticipates that it can generate sufficient liquidity through internally generated operating cash flows, revolving credit facilities, as well as the debt and equity capital markets to finance its property, plant and equipment expenditures and other commitments.

2014 Twelve Month Property Plant and Equipment Expenditures

During the twelve months ended December 31, 2014, the Generation Group incurred capital expenditures of $201.1 million, as compared to $49.5 million during the comparable period in 2013.

During the twelve months ended December 31, 2014, the Generation Group's Renewable Energy Division spent $197.1 million in capital expenditures, as compared to $46.9 million in the comparable period in 2013. The capital expenditures primarily relate to the completion of the Cornwall Solar and St. Damase Wind Facilities, and the construction of the Bakersfield Solar and Morse Wind Projects. The Generation Group's Thermal Energy Division net capital expenditures were $4.0 million, as compared to $2.6 million in the comparable period in 2013. The capital expenditures in the year were $1.2 million at Windsor Locks and $2.8 million at Sanger.

During the twelve months ended December 31, 2014, the Distribution Group invested $176.8 million in capital expenditures, as compared to $108.9 million during the comparable period in 2013. The capital expenditures primarily relate to the completion of a second supply line, reliability enhancements, and new business projects at the Granite State Electric System; improvement and replenishment opportunities at the CalPeco Electric System; leak prone pipe replacements, leak repairs and pipeline corrosion protection systems relating to enhancing safety and reliability at the EnergyNorth, Midstates, New England, and Peach State Gas Systems; and improvement, replenishment and new business projects at the water and wastewater utilities located in Arizona and at the Pine Bluff Water System.

2014 Fourth Quarter Property Plant and Equipment Expenditures

During the three months ended December 31, 2014, the Generation Group incurred capital expenditures of $60.1 million, as compared to $19.3 million during the comparable period in 2013. During the three months ended December 31, 2014, the Generation Group's Renewable Energy Division spent $59.6 million in capital expenditures, as compared to $18.0 million in the comparable period in 2013. The capital expenditures primarily relate to completion of construction at the St. Damase Wind Facility and the continued construction at the Bakersfield Solar Project. The Generation Group's Thermal Energy Division net capital expenditures were $0.5 million, as compared to $1.3 million in the comparable period in 2013. The 2014 thermal capital expenditures consist of $0.4 million relating to Windsor Locks Thermal Facility and $0.1 million relating to Sanger Thermal Facility.

During the three months ended December 31, 2014, the Distribution Group invested $77.4 million in capital expenditures, as compared to $43.4 million during the comparable period in 2013. The Distribution Group's investment was primarily related to reliability enhancements, and new business projects at the Granite State Electric System; improvement and replenishment opportunities at the CalPeco Electric System; leak prone pipe replacements, leak repairs and pipeline corrosion protection systems relating to enhancing safety and reliability at the EnergyNorth, Midstates, New England, and Peach State Gas Systems; and improvement, replenishment and new business projects at the water and wastewater utilities located in Arizona and at the Pine Bluff Water System.

Quebec Dam Safety Act

As a result of the dam safety legislation passed in Quebec (Bill C-93), the Generation Group has completed technical assessments on its hydroelectric facility dams owned or leased within the Province of Quebec. Out of these, nine assessments have been submitted to and accepted by the Quebec government. The assessments have identified possible remedial work at seven facilities. Of these seven, remediation work has now been completed at three facilities, monitoring activities and options analysis are being performed for two facilities, and remedial work is being planned at two facilities.

The Generation Group currently estimates further capital expenditures of approximately $7.9 million related to compliance with the legislation. It is anticipated that these expenditures will be invested over a period of several years approximately as follows:

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

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

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

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

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

On May 18, 2014, the Donnacona Hydro Facility experienced ice damage during the spring thaw and has been shut down. The Generation Group had previously planned capital expenditures for the Donnacona Hydro Facility in 2015 and 2016 in the amount of $7.8 million. It has been determined, in consultation with its 3rd party engineers, that a dam re-build is required to return the facility to operation. The Generation Group is currently evaluating environmental permitting and rebuild scenarios. Consequently, the Generation Group does not anticipate any near-term expenditures related to Bill C-93 compliance of the existing structure.

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

LIQUIDITY AND CAPITAL RESERVES

APUC has revolving operating facilities available for APUC, the Generation Group and the Distribution Group to manage the liquidity and working capital requirements of each division (collectively the "Facilities").

Bank Credit Facilities

The following table sets out the amounts drawn, letters of credit issued and outstanding amounts available to APUC and its operating groups as at December 31, 2014 under the Facilities:

	As at December 31, 2014				As at Dec 31 2013
(all dollar amounts in $ millions)	Corporate	Generation Group	Distribution Group	Total	Total
Committed Facilities	$ 65.0	$ 350.0	$ 232.0	$ 647.0	$ 477.7
Funds drawn on Facilities	—	(23.4)	(23.9)	(47.3)	(210.2)
Letters of Credit issued	(10.8)	(96.0)	(7.0)	(113.8)	(64.9)
Funds available for draws on the Facilities	**$ 54.2**	**$ 230.6**	**$ 201.1**	**$ 485.9**	$ 202.6
Cash on Hand				9.3	13.8
Total liquidity and capital reserves	**$ 54.2**	**$ 230.6**	**$ 201.1**	**$ 495.2**	$ 216.4

As at December 31, 2014, the Company's $65.0 million senior unsecured revolving credit facility (the "Corporate Credit Facility"), was undrawn and had $10.8 million of outstanding letters of credit. The facility matures on November 19, 2016 and is subject to customary covenants.

As at December 31, 2014, the $350.0 million Generation Credit Facility had drawn $23.4 million and had $96.0 million in outstanding letters of credit. On July 31, 2014, the Generation Group increased the credit available under its credit facility to $350 million from $200 million. The larger credit facility will be used to provide additional liquidity in support of the group's $1,225.0 million development portfolio to be completed over the next four years. In addition to the larger size, the maturity of the credit facility has been extended from three to four years extending to July 31, 2018.

As at December 31, 2014, the Distribution Group's $232.0 million (U.S. $200.0 million) senior unsecured revolving credit facility (the "Distribution Credit Facility") had drawn $23.9 million (U.S. $20.6 million) and had $7.0 million (U.S. $6.0 million)of outstanding letters of credit. The facility matures on September 30, 2018 and is subject to customary covenants

Long Term Debt

On January 17, 2104, the Generation Group issued $200.0 million 4.65% senior unsecured debentures with a maturity date of February 15, 2022 (the "Generation Debentures") pursuant to a private placement in Canada and the United States. The Generation Debentures were sold at a price of $99.864 per $100.00 principal amount resulting in an effective yield of 4.67%. Concurrent with the offering, the Generation Group entered into a fixed for fixed cross currency swap, coterminous with the Generation 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%.

On December 31, 2014, the U.S. $19.2 million senior debt for the Sanger Thermal Facility was repaid.

As at December 31, 2014, the weighted average tenor of APUC's total long term debt is approximately 8.0 years with an average interest rate of 4.9%.

Contractual Obligations

Information concerning contractual obligations as of December 31, 2014 is shown below:

(all dollar amounts in $ millions)		Total		Due less than 1 year		Due 1 to 3 years		Due 4 to 5 years		Due after 5 years
Long-term debt obligations	$	1,280.0		9.1		91.0		218.8		961.1
Advances in aid of construction	$	81.1		1.1		—		—		80.0
Interest on long-term debt obligations	$	438.3		64.2		125.3		102.1		146.7
Purchase obligations	$	267.9		267.9						
Environmental obligation	$	72.6		19.6		36.6		6.1		10.3
Derivative financial instruments:										
Cross currency swap	$	36.3		1.5		3.0		2.4		29.4
Interest rate forward	$	4.7		—		—		4.7		—
Interest rate swap	$	1.4		1.4		—		—		—
Energy derivative contracts	$	2.9		2.3		0.6		—		—
Purchased power	$	118.2		118.2		—		—		—
Gas delivery, service and supply agreements	$	264.3		52.8		68.0		55.3		88.2
Long term service agreements	$	637.3		28.6		64.7		62.9		481.1
Capital projects	$	22.0		22.0		—		—		—
Operating leases	$	121.1		5.6		9.6		8.5		97.4
Other obligations	$	40.5		9.9		0.9		—		29.7
Total obligations	**$**	**3,388.6**	**$**	**604.2**	**$**	**399.7**	**$**	**460.8**	**$**	**1,923.9**

Equity

The common shares of APUC are publicly traded on the Toronto Stock Exchange ("TSX"). As at December 31, 2014, APUC had 238,149,468 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.

On September 16, 2014, APUC completed the 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 offering and an additional 2,529,000 common shares were issued on the same terms and conditions of the offering. As a result, APUC issued 19,389,000 common shares under the offering for the total gross proceeds of approximately $172.6 million.

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

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, 2014, APUC had outstanding:

- 4,800,000 cumulative rate reset Series A preferred 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 Wind Energy LP; and
- 4,000,000 cumulative rate reset Series D preferred shares, yielding 5.0% annually for the initial five-year period ending on March 31, 2019.

APUC has a shareholder dividend reinvestment plan (the "Reinvestment Plan") for registered holders of shares of APUC. As at December 31, 2014, 63.8 million common shares representing approximately 27% of total shares outstanding had been registered with the Reinvestment Plan and 2,262,885 shares were issued during the year ended December 31, 2014. During the quarter ended December 31, 2014, 665,172 common shares were issued under the Reinvestment Plan, and subsequent to the end of the quarter, on January 15, 2015, an additional 706,680 common shares were issued under the Reinvestment Plan.

Emera subscription receipts

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

On October 7, 2014, the Company issued 8,708,170 Subscription Receipts of APUC at a purchase price of $8.90 per Subscription Receipt for an aggregate subscription price of $77.5 million. The investment was made under the Strategic Investment Agreement between Emera and APUC, in support of the acquisition by APUC of the Odell Wind Project in Minnesota (the "Odell Acquisition"). The proceeds of the subscription are intended to be used by APUC to partially finance the Odell Acquisition and the completion of the Odell Wind Project. Subject to adjustments as provided in the applicable subscription agreement, Emera may convert the Subscription Receipts into common shares of APUC on a one-for-one basis on November 14, 2015 (the first anniversary of the closing of the Odell Acquisition) or the commercial operation date of the Odell Wind Project, whichever is first to occur.

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

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

As at March 15, 2015, in total, Emera owns 50,126,766 APUC common shares representing approximately 21.0% of the total outstanding common shares of the Company, and there are 12,024,753 subscription receipts currently held by Emera. APUC believes issuance of shares to Emera is an efficient way to raise equity as it avoids underwriting fees, legal expenses and other costs associated with raising equity in the capital markets.

SHARE BASED COMPENSATION PLANS

For the three and twelve months ended December 31, 2014, APUC recorded $1.1 million and $3.2 million, respectively, in total share-based compensation expense, as compared to $0.6 million and $2.0 million, respectively, for the same period in 2013. No tax deduction was realized in the current year. The compensation expense is recorded as part of administrative expenses in the Consolidated Statement of Operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at December 31, 2014, total unrecognized compensation costs related to non-vested options and share unit awards were $2.1 million and $2.4 million, respectively, and are expected to be recognized over a period of 1.71 and 1.61 years, respectively.

Stock Option Plan

APUC has a stock option plan that permits the grant of share options to key officers, directors, employees and selected service providers. Except in certain circumstances, the term of an option shall not exceed ten (10) years from the date of the grant of the option.

APUC determines the fair value of options granted using the Black-Scholes option-pricing model. The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date. During the year, the Company issued 969,998 options to employees of the Company.

As at December 31, 2014, a total of 5,537,127 options had been issued and outstanding under the plan.

Performance Share Units

APUC issues performance share units ("PSUs") to certain members of management other than senior executives as part of APUC's long-term incentive program. The PSUs provide for settlement in cash or shares at the election of APUC.

During the year, the Company settled 11,406 vested PSUs for $0.2 million in cash. The plan provides for settlement in cash or shares at the election of the Company. At the annual general meeting held on June 18, 2014, the shareholders approved a maximum of 500,000 shares issuable from Treasury to settle PSUs. With the ability to issue shares from Treasury or purchase shares on the market, the Company expects to settle the remaining PSUs in shares. As a result, the PSUs continue to be accounted for as equity awards. During the year, the Company issued 407,962 PSUs to executives and employees of the Company.

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

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. 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 year, the Company issued 35,455 DSUs to the directors of the Company.

As at December 31, 2014, a total of 110,241 DSUs had been granted under the DSU plan.

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 of APUC. 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 Company issued 93,598 common shares to employees under the ESPP plan.

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

MANAGEMENT OF CAPITAL STRUCTURE

APUC views its capital structure in terms of its debt and equity levels, at its individual operating groups and at an overall company level.

APUC's objectives when managing capital are:

- To maintain its capital structure consistent with investment grade credit metrics appropriate to the sectors in which APUC operates;
- To maintain appropriate debt and equity levels in conjunction with standard industry practices and to limit financial constraints on the use of capital;
- To ensure capital is available to finance capital expenditures sufficient to maintain existing assets;
- To ensure generation of cash is sufficient to fund sustainable dividends to shareholders as well as meet current tax and internal capital requirements;
- To maintain sufficient cash reserves on hand to ensure sustainable dividends made to shareholders; and
- To have appropriately sized revolving credit facilities available for ongoing investment in growth and development opportunities.

APUC monitors its cash position on a regular basis to ensure funds are available to meet current normal as well as capital and other expenditures. In addition, APUC continuously reviews its capital structure to ensure its individual business groups are using a capital structure which is appropriate for their respective industries.

RELATED PARTY TRANSACTIONS

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

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

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

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

Due to and from related parties

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

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

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

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

Effective December 31, 2013, APUC acquired the Parties' shares of Algonquin Power Corporation Inc. ("APC") which owns the partnership interest in the 18MW Long Sault Hydro Facility and the partnership interest in the BCI Thermal Facility plant for an amount equal to $3.8 million. As APUC already consolidates Long Sault Hydro Facility as a VIE, the acquisition of this partnership interest was treated as an equity transaction. The payment resulted in an adjustment to deferred tax liability of $10.7 million in regards to tax attributes acquired with the partnership interests and an adjustment of $14.6 million to equity of the shareholders of the Company as the partnership interests had a nominal carrying amount prior to the exchange.

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

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

St. Leon LP Units

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

On January 1, 2013, the Company issued 100 redeemable Series C preferred shares and exchanged such shares for the 100 Class B units (note 11) including 36 units held indirectly by Senior Management. The Series C preferred shares provide dividends identical to what is expected from the Class B units, as determined by independent consultants retained by the Independent Board Committee. As of January 1, 2013, no Senior Executives have any further direct or indirect ownership of the St. Leon Wind Facility.

Office Facilities

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

Chartered Aircraft

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

Trafalgar

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

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

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

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

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

Other

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

ENTERPRISE RISK MANAGEMENT

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

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

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

The development and execution of risk treatment plans are actively monitored by the ERM team through a centralized risk register software application. APUC's internal audit team is responsible for conducting audits to validate and test the effectiveness of controls for the key risks. Audit findings are discussed with business owners and 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, Executive Risk Steering Committee, and the Board of Directors for consideration.

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

The risks discussed below are not intended as a complete list of all exposures that APUC is encountering or may encounter. A further assessment of APUC and its subsidiaries' business risks is also set out in the most recent AIF.

Treasury Risk Management

Foreign Currency Risk

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

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

Market Price Risk

The Distribution Business Group is not exposed to market price risk as rates charged to customers are stipulated by the respective regulatory bodies.

The Generation Group predominantly enters into long term PPAs for its generation assets and hence is not exposed to market risk for this portion of its portfolio. Where a generating asset is not covered by a power purchase contract, the Generation Group may seek to mitigate market risk exposure by entering into financial or physical power hedges requiring that a specified amount of power be delivered at a specified time in return for a fixed price. There is a risk that the Company is not able to generate the specified amount of power at the specified time resulting in production shortfalls under the hedge that then requires the Company to purchase power in the merchant market. To mitigate the risk of production shortfalls under hedges, the Generation Group generally seeks to structure hedges to cover less than 100% of the anticipated production, thereby reducing the risk of not producing the minimum hedge quantities. Nevertheless, due to unpredictability in the natural resource or due to mechanical failures, production shortfalls may be such that the Generation Group may still be forced to purchase power in the merchant market at prevailing rates to settle against a hedge.

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

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

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

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

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

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

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

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

Credit/Counterparty Risk

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

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

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

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

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

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

The natural gas distribution systems accounts receivable balances related to the natural gas utilities total U.S. $62.0 million, while electric distribution systems accounts receivable balances related to the electric utilities total U.S. 24.3 million. The natural gas and electrical utilities, respectively, derive over 91% and 87% of their revenue from residential customers.

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

Interest Rate Risk

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

- The Corporate Credit Facility is subject to a variable interest rate. The APUC Facility has no amounts outstanding as at December 31, 2014. As a result, a 100 basis point change in the variable rate charged would not impact interest expense.

- The Generation Credit Facility had $23.4 million outstanding as at December 31, 2014. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.2 million annually.
- The Distribution Credit Facility had $23.9 million outstanding as at December 31, 2014. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.2 million annually.
- The Generation Group is party to an interest rate swap whereby the group pays a fixed interest rate of 4.47% on a notional amount of $60.5 and receives floating interest at 90 day CDOR, up to the expiry of the swap in September 2015. This interest rate swap is not being accounted for as a hedge and, consequently, changes in fair value are recorded in earnings as they occur. As a result, a 100 basis point change in the variable rate would impact derivative gains/losses by $0.01 million.
- The Shady Oaks Senior Debt Facility had $88.2 million outstanding as at December 31, 2014. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.9 million annually.

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

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

Tax Risk and Uncertainty

Although APUC is of the view that all expenses being claimed by APUC are reasonable and that the cost amount of APUC's depreciable properties have been correctly determined, there can be no assurance that the Canada Revenue Agency or the Internal Revenue Service will agree. A successful challenge by either agency regarding the deductibility of such expenses or the correctness of such cost amounts could impact the return to shareholders.

Unit Exchange Transaction

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

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

Should APUC receive a Notice of Reassessment covering the 2009, 2010, 2011, 2012 and 2013 taxation years, APUC will be required to make a deposit payment of 50% of the tax liability (including interest and any applicable penalties) claimed by the CRA in order to appeal the expected reassessment. Based on the tax amounts related to the 2009 to 2013 taxation years, that payment amount would be approximately $17.5 million. Additionally, assuming the 2014 taxation year will be similarly reassessed, a further payment of approximately $3.1 million would also be required. APUC would also be required to make a deposit payment of 50% of the taxes the CRA claims are owed in any future tax year if the CRA were to issue a similar notice of reassessment for such years and APUC were to appeal it.

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

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

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

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

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

Liquidity Risk

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

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

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

APUC currently pays a dividend of U.S. $0.35 per common share per year. The Board determines the amount of dividends to be paid, consistent with APUC's commitment to the stability and sustainability of future dividends, after providing for amounts required to administer and operate APUC and its subsidiaries, for capital expenditures in growth and development opportunities, to meet current tax requirements, and to fund working capital that, in its judgment, ensures APUC's long-term success. Based on the level of common share dividends paid during the year ended December 31, 2014, cash provided by operating activities exceeded common share dividends declared by 2.2 times and Adjusted Cash From Operations exceeds common share dividends by 3.4 times.

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

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

Commodity Price Risk

The Generation Group's exposure to commodity prices is primarily limited to exposure to natural gas price risk. The Distribution Groups is exposed to energy 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 174,000 MW-hrs in fiscal 2015, of which 90,000 MW-hrs is presently contracted. While the Tinker Hydro Facility is expected to provide the majority of the energy required to service these customers, the Maritime region anticipates having to purchase approximately 80,000 MW-hrs of its energy requirements at the ISO-NE summer spot rates to supplement self-generated energy should the Maritime region be able to reach the estimated 174,000 MW-hrs. The risk associated with the expected market purchases of 80,000 MW-hrs is mitigated through the use of short-term financial energy hedge contracts which cover approximately 90% of the Maritime region's anticipated purchases during the price-volatile winter months at an average rate of approximately $65 per MW-hr. For the amount of anticipated purchases not covered by hedge contracts, each $10.00 change per MW-hr in the market prices in ISO-NE would result in a change in expense of $0.5 million on an annualized basis.

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 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 NHPUC on a semi-annual basis. The Granite State Electric System is only committed to the winning Default Service supplier(s) after approval by the NHPUC so that there is no risk of commodity commitment without pass-through rate recovery.

The EnergyNorth Natural Gas System purchases pipeline capacity, storage and commodity from a variety of counterparties. The EnergyNorth Natural Gas System's portfolio of assets and its planning and forecasting methodology are approved by the NHPUC bi-annually through an Integrated Resource Plan filing. In addition, EnergyNorth Natural Gas System files with the NHPUC for recovery of its transportation and commodity costs through a semi-annual basis through the 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 pass-through to customers through the COG filing and the approved rates in said filing. Should commodity prices increase or decrease relative to the initial semi-annual COG rate filing, the EnergyNorth Natural Gas System has the right to automatically adjust its rates going forward in order to minimize any under or over collection of its gas costs. In addition, any under collections may be carried forward with interest to the next year's period COG filing, i.e. winter to winter and summer to summer.

The purchases pipeline capacity, storage and commodity from a variety of counterparties, and files with the three individual State Commissions for recovery of its transportation and commodity costs through an annual 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 Company 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 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.

OPERATIONAL RISK MANAGEMENT

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

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

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

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

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

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

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

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

Regulatory Risk

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

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

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

Condemnation Expropriation Proceedings

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

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 Distribution 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 Distribution 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 Distribution Group expects to be allowed to earn a return on such investment.

In conjunction with recent acquisitions and developed projects, the Company 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.

Environmental Risks

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

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

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

In order to monitor and mitigate these risks and to remain within the regulatory requirements appropriate for these assets, the Generation and Distribution Groups investigate promptly all reported accidental releases to take all required remedial actions and manages hazardous waste and universal waste streams in accordance with the applicable Federal and State Legislation.

The primary risks associated with the operation of gas distribution systems are related to uncontrolled natural gas releases, equipment damage by construction equipment/third parties or severe weather events. The gas distribution assets are regulated by the Pipeline Hazardous Material Safety Administration (PHMSA) under the United States Department of Transportation and their respective State regulations in which the assets are located. Natural Gas Distribution Systems are subject to detailed inspections by State Regulatory Agencies to ensure adherence to applicable regulations. State Regulator Agencies review the Company's policies in reference to operation and maintenance, construction, training, emergency response, reporting, contractor management and measurements. The Distribution Group monitors all aspects of pipeline safety and quickly mitigates any identified concerns.

The primary risks associated with the operation of power generation facilities are related to uncontrolled contaminant releases (or above the permitted limits), not being in continued compliance with permits and licenses obligations such as, continuous emissions monitoring, periodic reporting/source testing, general performance/operating conditions, operations adjustments (wind projects) resulting from post construction wildlife mortality monitoring, dam safety, potential accidental release of mineral oil or other hazardous materials to the environment.

The Distribution Group's ongoing operations and historic activities are subject to various federal, state and local environmental laws and regulations and are regulated by agencies such as the United States Environmental Protection Agency, the New Hampshire Department of Environmental Services ("NHDES"). Similar to other industrial companies, the gas and electric distribution utilities generate certain hazardous wastes. 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 regulated utilities these costs are often allowed in rate case proceedings to be recovered from rate payers over a specified period.

Prior to their acquisition by the Distribution Group, the EnergyNorth Gas Utility, the Granite State Electric Utility, and the New England Gas System were named as potentially responsible parties for remediation of several sites at which hazardous waste is alleged to have been disposed as a result of historic operations of Manufactured Gas Plants ("MGP") and related facilities. The Distribution Group is currently investigating and remediating, as necessary, those MGP and related sites where it is the lead project manager in accordance with plans submitted to the NHDES. The Distribution Group believes that obligations imposed on it because of those sites will not have a material impact on its results of operations or financial position.

The Distribution Group estimates the remaining undiscounted and unescalated cost of these MGP-related environmental cleanup activities will be $72.6 million which, at discount rates ranging from 2.1% to 3.4%, represents $72.3 million on a discounted basis, as the Distribution Group's estimate of costs for known issues that has been accrued at December 31, 2014. By rate orders, the Regulator provided for the recovery of site investigation and remediation costs and accordingly, at December 31, 2014 the Company has reflected a regulatory asset of $102.7 million for the remediation of the MGP and related sites.

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

Cycles and Seasonality

Generation Group

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

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

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

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

Distribution Group

The Distribution Group's 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 Distribution Group's demand for energy from its electric distribution systems is primarily affected by weather conditions and conservation initiatives. The Distribution Group provides information and programs to its customers to encourage the conservation of energy. In turn, demand may be reduced which could have short term adverse impacts to revenues.

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

The Company attempts to mitigate the above noted risks by seeking regulatory mechanisms during rate case proceedings. Certain jurisdictions have approved constructs to mitigate demand fluctuations. For example, at the Peach State Gas System in Georgia, a weather normalization adjustment is applied to customer bills during the months of October through May that adjusts commodity rates to stabilize the revenues of the utility for changes in billing units attributable to weather patterns.

Not all regulatory jurisdictions in which the Distribution Group operates have approved mechanisms to mitigate demand fluctuations.

Development and Construction Risk

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

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

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

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

Obligations to Serve

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

Litigation Risks and Other Contingencies

APUC and certain of its subsidiaries are involved in various litigations, claims and other legal proceedings that arise from time to time in the ordinary course of business. Any accruals for contingencies related to these items are recorded in the financial statements at the time it is concluded that a material financial loss is likely and the related liability is estimable. Anticipated recoveries under existing insurance policies are recorded when reasonably assured of recovery.

Trafalgar Proceedings

Trafalgar commenced an action in 1999 in U.S. District Court against APUC, and various other entities related to them in connection with, among other things, the sale of the Trafalgar Class B Note by Aetna Life Insurance Company to APUC and in connection with the foreclosure on the security for the Trafalgar Class B Note which includes interests in the Trafalgar entities and in the hydroelectric generating facilities in New York (the "Trafalgar Hydro Facilities"). In 2001, Trafalgar and other entities also filed for Chapter 11 reorganization in bankruptcy court and also filed a multi-count adversary complaint against certain subsidiary entities of APUC, which complaint was then transferred to the District Court. In 2006, the District Court decided that Aetna had complied with the provisions concerning the sale of the Trafalgar Class B Note, that APUC was therefore the holder and owner of the Trafalgar Class B Note, and that all other claims by Trafalgar with respect to the transfer of the Trafalgar Class B Note were without merit. Further, on November 6, 2008, the claims that were remaining in the District Court against APUC were dismissed by summary judgment. On October 22, 2009, Trafalgar filed an appeal from the November 6, 2008 summary judgment to the United States Court of Appeals for the Second Circuit. As discussed further below, as the proceedings continued, the United States Second Circuit Court of Appeals, among other things, (i) on November 2, 2010 dismissed the claims against APUC in the civil proceedings; and (ii) on January 30, 2013, held that Algonquin has a security interest in Trafalgar's engineering malpractice claim and its proceeds.

With respect to the civil proceedings, the United States Second Circuit Court of Appeals dismissed all the claims against APUC in the civil proceedings and remanded one issue to the District Court. On April 3, 2012, the District Court granted APUC summary judgment on its counter-claims against Trafalgar. The District Court found that Trafalgar was in default of the indenture and the loan agreements and that APUC was entitled to proceed to enforce its rights against its collateral. Trafalgar filed a notice of appeal of the Memorandum-Decision and Order. The appeal was argued on March 21, 2013. On March 25, 2013, the United States Second Circuit Court of Appeals affirmed the decision of the District Court giving APUC judgment on its claims. Trafalgar asked the United States Second Circuit Court of Appeals for reconsideration of its decision or to certify a legal question to the Connecticut Supreme Court. On May 21, 2013, the United States Second Circuit Court of Appeals denied Trafalgar's petition and the matter was sent back to the District Court for further proceedings with respect to the enforcement of APUC's remedies under the loan documents, including the calculation of the debt and the disposition of collateral. The District Court entered judgment in favor of APUC with regard to the default and APUC's entitlement to recourse to the collateral, but without determining the amount due under the note. The District Court then closed the case.

With respect to the bankruptcy proceedings, on January 30, 2013, the United States Second Circuit Court of Appeals held that Algonquin did have a security interest in Trafalgar's engineering malpractice claim and its proceeds. On February 20, 2013, Trafalgar filed a petition for a rehearing with the United States Second Circuit Court of Appeals, and in the alternative, sought to have the Second Circuit certify a legal question to the New York State Court of Appeals. The Second Circuit denied the petition and certification request which petition was denied on June 17, 2013. On September 16, 2013, Trafalgar filed a Petition for a Writ of Certiorari with the United States Supreme Court. Algonquin filed a brief in opposition to the Petition on October 18, 2013. On December 2, 2013, the United States Supreme Court denied Trafalgar's petition for a Writ of Certiorari. Algonquin filed and served a motion seeking an order terminating the automatic stay and directing the distribution of the funds held in the escrow account to Algonquin. Algonquin's motion for relief from the automatic stay has been denied without prejudice to re-filing the motion after the court determines the amount of Algonquin's claim and the validity of any defenses to the claim. Algonquin and Trafalgar have each filed motions with the Court seeking a determination of those issues. Those motions are under consideration by the Court.

The Court has approved the sale of all seven of the Trafalgar facilities. Of the seven, one has closed while the other six is anticipated to close upon obtaining regulatory approval. The parties are attempting to resolve this matter through good faith settlement negotiations.

Côte Ste-Catherine Water Lease Dues

On December 19, 1996, the Attorney General of Québec (the "Québec AG") filed suit in Québec Superior Court against Algonquin Développement (Côte Ste-Catherine) Inc. (Développement Hydromega), a predecessor company to an a subsidiary entity of APUC. The Québec AG at trial claimed $5.4 million for amounts that Algonquin Développement Côte Ste-Catherine Inc. had been paying to Seaway Management under the water lease relating to the Côte Ste-Catherine hydroelectric generating facility. Algonquin Développement (Côte Ste-Catherine) Inc. brought the Attorney General of Canada into the proceedings. On March 27, 2009, the Superior Court dismissed the claim of the Québec AG. Québec AG appealed this decision on April 24, 2009, and the appeal was heard in January 2011.

On October 21, 2011, the Québec Court of Appeal ordered Algonquin Développement (Côte Ste-Catherine) Inc. to pay approximately $5.4 million (including interest) to the government of Québec relating to water lease payments that Algonquin Développement (Côte Ste-Catherine) Inc. has been paying to the Seaway Management under the water lease in prior years. The water lease with Seaway Management contains an indemnification clause which management believes mitigates this claim and management intends to vigorously defend its position. The potential unrecoverable loss, if any, for the related prior periods could be up to $6.0 million. The parties are attempting to resolve this matter through good faith negotiations.

Long Sault global adjustment claim

In December 2012, N-R Power and Energy Corporation, Algonquin Power (Long Sault) Partnership, and N-R Power Partnership ("Long Sault") commenced proceedings (together with the other similarly affected non-utility generators) against the OEFC relating to the OEFC's interpretation of certain provisions of a PPA between Long Sault and the OEFC, in relation to the use of the global adjustment ("GA") as a price escalator. As a result of the OEFC's application of the new GA calculation to the calculation of total market cost of electricity ("TMC") of and, in turn, an index derived from TMC, the rate OEFC has paid to Long Sault under the PPA beginning with the application of OEFC's new TMC calculation in July 2011 has not escalated as contemplated in the PPA and term sheet. A Notice of Application was issued at the end of December 2012 with supporting materials filed at the end of April 2013. The Application was heard in May 2014. On March 12, 2015, the Ontario Superior Court of Justice ruled that the methodology that the OEFC used from January 1, 2011 onward to calculate payments under Long Sault's PPA, and those of other producers, did not comply with the terms of those PPAs. The decision further requires the OEFC to revert to its pre-2011 methodology for calculating payments and to pay producers the difference between the payments calculated by the OEFC since 2011 and the amount of the payments they would have received using the pre-2011 methodology, plus interest and costs. The OEFC has until April 13, 2015 to appeal this decision.

Dimos and Katsekas Breach of Contract Claim

On September 30, 2013, Dimos and Katsekas previous owners of the Clement Dam Hydroelectric, LLC. ("Clement Dam Hydro Facility"), filed a demand for arbitration with Algonquin Power Fund (America) Inc. ("APFA") alleging breach of the Purchase Agreement and Royalty Agreement. The claim is for $1,345,257 for alleged breach of such agreements and $155,821 for alleged unpaid royalties. The plaintiffs have demanded arbitration pursuant to such agreements. An arbitration hearing date is scheduled for May, 2015.

The Royalty Agreement obligations were guaranteed by the Clement Dam Hydro Facility pursuant to a guaranty. On December 14, 2014, Dimos and Katsekas filed a complaint against the Clement Dam Hydro Facility which seeks to enforce certain obligations under a guaranty. In the event the claimants prevail against APFA in the aforementioned arbitration, and APFA does not pay any judgment rendered against it, claimants will pursue their claims against the Clement Dam Hydro Facility. APFA is defending the Clement Dam in this matter pursuant to the sale agreement with the purchaser of the Clement Dam Hydro Facility. At present, the litigation has been stayed pending the outcome of the arbitration proceeding.

Synergics Energy Services, LLC, Breach of Contract Claim

On September 4, 2013, the plaintiff, previous owners of the Great Falls Hydro Facility, filed a complaint for alleged breach of the 2000 purchase and sale agreement and failure to pay a transfer payment thereunder in the event of the sale of the hydro facility. The claim is for $3,000,000 for alleged breach of the 2000 purchase and sale agreement. The case has been settled.

Conex Energy-Canada, LLC and Conex Energy, Inc. Breach of Contract Claim

On October 31, 2013, the plaintiffs filed a complaint for, among other things, alleged breach of a confidential agreement in relation to the development and construction of the 10-megawatt solar photovoltaic Cornwall Solar Facility. On March 3, 2014, Algonquin brought a motion to dismiss the case. The Court has since dismissed the case.

Bryson School District in Texas Property Taxes Claim

On February 10, 2014, the Generation Group received correspondence from the Bryson School District (the "School District") in Texas regarding Senate Wind LLC's property taxes claiming the Senate Wind Facility owes an additional $2.2 million of property taxes based on an indemnity in the 2010 agreement with the School District. Senate Wind LLC and the District have settled this matter.

QUARTERLY FINANCIAL INFORMATION

The following is a summary of unaudited quarterly financial information for the eight quarter ended December 31, 2014:

(all dollar amounts in $ millions except per share information)	1st Quarter 2014	2nd Quarter 2014	3rd Quarter 2014	4th Quarter 2014
Revenue	$ 343.5	$ 189.3	$ 151.9	$ 259.3
Adjusted EBITDA	97.5	66.4	41.4	84.3
Net earnings / (loss) attributable to shareholders from continuing operations	35.6	15.3	(6.1)	33.1
Net earnings / (loss) attributable to shareholders	35.9	14.6	(6.3)	31.6
Net earnings / (loss) per share from continuing operations	0.16	0.06	(0.04)	0.13
Net earnings / (loss) per share	0.17	0.06	(0.04)	0.13
Adjusted net earnings	36.8	16.5	(0.4)	35.2
Adjust net earnings per share	0.17	0.07	(0.01)	0.14
Total Assets	3,652.7	3,561.9	3,808.5	4,113.7
Long term debt[1]	1,409.4	1,389.3	1,413.5	1,280.0
Dividend declared per common share	0.09	0.09	0.10	0.10

	1st Quarter 2013	2nd Quarter 2013	3rd Quarter 2013	4th Quarter 2013
Revenue	$ 193.3	$ 148.8	$ 127.9	$ 205.3
Adjusted EBITDA	62.8	56.5	40.2	68.5
Net earnings / (loss) attributable to shareholders from continuing operations	20.3	15.8	6.3	19.8
Net earnings/(loss) attributable to shareholders	19.2	(18.1)	6.0	13.2
Net earnings / (loss) per share from continuing operations	0.09	0.08	0.02	0.09
Net earnings/(loss) per share	0.09	(0.09)	0.02	0.06
Adjusted net earnings	19.6	15.4	6.9	18.8
Adjust net earnings per share	0.09	0.08	0.03	0.08
Total Assets	3,476.5	3,201.8	3,156.4	3,476.5
Long term debt[1]	1,255.5	1,091.5	1,092.0	1,255.6
Dividend declared per common share	0.08	0.09	0.09	0.09

[1] Long term debt includes current and long term portion of debt and convertible debentures

The quarterly results are impacted by various factors including seasonal fluctuations and acquisitions of facilities as noted in this MD&A.

Quarterly revenues have fluctuated between $127.9 million and $343.5 million over the prior two year period. A number of factors impact quarterly results including acquisitions, seasonal fluctuations, hydrology and winter and summer rates built into the PPAs. In addition, a factor impacting revenues year over year is the fluctuation in the strength of the Canadian dollar relative to the U.S. dollar which can result in significant changes in reported revenue from U.S. operations.

Quarterly net earnings attributable to shareholders have fluctuated between net earnings attributable to shareholders of $35.9 million and a net loss of $18.1 million over the prior two year period. Earnings have been significantly impacted by non-cash factors such as deferred tax recovery and expense, impairment of intangibles, property, plant and equipment and mark-to-market gains and losses on financial instruments.

ISSUANCE OF FOURTH QUARTER AND YEAR END FINANCIAL RESULTS

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

DISCLOSURE CONTROLS

At the end of the fiscal year ended December 31, 2014, APUC carried out an evaluation, under the supervision of and with the participation of APUC's management, including the Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO"), of the effectiveness of the design and operations of APUC's disclosure controls and procedures (as defined in Rule 13a – 15(e) and Rule 15d – 15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")). Based on that evaluation, the CEO and the CFO have concluded that as of December 31, 2014, APUC's disclosure controls and procedures are effective.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

APUC's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of APUC; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of APUC are being made only in accordance with authorizations of management and directors of APUC; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of APUC's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect all misstatements. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

During the year ended December 31, 2014, there has been no change in APUC's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, APUC's internal control over financial reporting. On May 14, 2013, the Committee of Sponsoring Organizations of the Treadway Commission (COSO) published? an updated Internal Control - Integrated Framework (2013) and related illustrative documents. The company adopted the new framework in 2014.

Management conducted an evaluation of the design and operation of APUC's internal control over financial reporting as of December 31, 2014 based on the criteria set forth in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. This evaluation included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls, and a conclusion on this evaluation. Based on this evaluation, management has concluded that APUC's internal control over financial reporting was effective as of December 31, 2014.

CRITICAL ACCOUNTING ESTIMATES AND POLICIES

The preparation of consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, related amounts of revenues and expenses, and disclosure of contingent assets and liabilities. Significant areas requiring the use of management estimates relate to the useful lives and recoverability of depreciable assets, recoverability of deferred tax assets, rate-regulation, unbilled revenue, pension and post-employment benefits, fair value of derivatives and fair value of assets and liabilities acquired in a business combination. Actual results may differ from these estimates.

APUC's significant accounting policies are discussed in Note 1 to the consolidated financial statements. Management believes the following accounting policies involve the application of critical accounting estimates. Accordingly, these accounting estimates have been reviewed and discussed with the Audit Committee of the Board of Directors of APUC.

Estimated useful lives and recoverability of Long-Lived Assets, Intangibles and Goodwill

The provisions for depreciation of property and equipment for financial reporting purposes are made on the straight-line method based on the estimated service lives of the assets. Depreciation rates on utility assets are subject to regulatory review and approval, and depreciation expense is recovered through rates set by ratemaking authorities. The recovery of those costs is dependent on the ratemaking process. Non-regulated property and equipment are depreciated on a straight-line basis over useful lives of the related assets. Management believes the lives and methods of determining depreciation are reasonable, however, changes in economic conditions affecting the industries could result in a reduction of the estimated useful lives of those non-regulated assets or in an impairment write-down of the carrying value of these properties.

The carrying value of long-lived assets, including identifiable intangibles and goodwill, is reviewed whenever events or changes in circumstances indicate that such carrying values may not be recoverable. Some of the factors APUC considers as indicators of impairment include whether a facility is operating, its plan for return to service, external influences such as natural disasters, energy pricing and profitability and changes in regulation. Changes in circumstances, market conditions and estimates of future cash flows could negatively affect the recovery of APUC's assets and result in an impairment charge.

Valuation of Deferred Tax Assets

Income taxes are accounted for using the asset and liability method. Under this method, deferred income taxes are recognized, at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities, as well as operating loss and tax credit carryforwards. The amount of deferred tax assets recognized is limited to the amount of the benefit that is more likely than not to be realized.

In assessing the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized and provides any necessary valuation allowances as required. Although management believes the assumptions, judgments and estimates are reasonable, changes in tax laws and changes in operations could significantly impact the amounts provided for income taxes in our financial statements.

Accounting for Rate Regulation

Accounting guidance for regulated operations provides that rate-regulated entities account for and report assets and liabilities consistent with the recovery of those incurred costs in rates if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. This accounting guidance is applied to the Distribution Group's operations. Certain expenses and revenues subject to utility regulation or rate determination normally reflected in income are deferred on the balance sheet as regulatory assets or liabilities and are recognized in income as the related amounts are included in service rates and recovered from or refunded to customers. Regulatory assets and liabilities are recorded when it is probable that these items will be recovered or reflected in future rates. Determining probability requires significant judgment on the part of management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders and industry practice. If events were to occur that would make the recovery of these assets and liabilities no longer probable, these regulatory assets and liabilities would be required to be written off or written down.

Unbilled Energy Revenues

Revenues related to natural gas, electricity and water delivery are generally recognized upon delivery to customers. The determination of customer billings is based on a systematic reading of meters throughout the month. At the end of each month, amounts of natural gas, energy or water provided to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recorded. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns compared to normal, total volumes supplied to the system, line losses, economic impacts, and composition of customer classes. Estimates are reversed in the following month and actual revenue is recorded based on subsequent meter readings.

Derivatives

APUC uses derivative instruments to manage exposure to changes in commodity prices, foreign exchange rates, and interest rates. Management's judgment is required to determine if a transaction meets the definition of a derivative and, if it does, whether the normal purchases and sales exception applies or whether individual transactions qualify for hedge accounting treatment. Management's judgment is also required to determine the fair value of derivative transactions. APUC determines the fair value of derivative instruments based on forward market prices in active markets adjusted for nonperformance risk.

A significant change in estimate could affect APUC's results of operations if the hedging relationship was considered no longer effective.

Pension and Post-employment Benefits

In conjunction with recent utilities acquisitions, the Company assumed defined benefit pension and post-employment benefit plans for qualifying employees in the related acquired businesses. The obligations and related costs are calculated using actuarial concepts, which include critical assumptions related to the discount rate, expected rate of return on plan assets and medical cost trend rates. These assumptions are important elements of expense and/or liability measurement and are updated on an annual basis, or upon the occurrence of significant events. The Company used the new mortality tables (RP-2014) and the mortality improvement scale (MP-2014) that were recently released by the Society of Actuaries in the current year assumptions. This change resulted in an increase to the pension and post-employment obligations of approximately U.S. $16.5 million.

Business Combinations

The Company has completed a number of business acquisitions in the past few years. Management's judgment is required to estimate the purchase price, to identify and to fair value all assets and liabilities acquired. The determination of the fair value of assets and liabilities acquired is based upon management's estimates and certain assumptions generally included in a present value calculation of the related cash flows. A significant change in estimate could affect APUC's results of operations.

Additional disclosure of APUC's critical accounting estimates is also available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com.

MANAGEMENT'S REPORT

Financial Reporting

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

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

Internal Control over Financial Reporting

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

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2014, based on the framework established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2014.

March 16, 2015

Ian Robertson
Chief Executive Officer

David Bronicheski
Chief Financial Officer

INDEPENDENT AUDITORS' REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders of Algonquin Power & Utilities Corp.

We have audited the accompanying consolidated financial statements of Algonquin Power & Utilities Corp., which comprise the consolidated balance sheets as at December 31, 2014 and 2013 and the consolidated statements of operations, comprehensive income, equity, and cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

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

Auditors' responsibility

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

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

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Algonquin Power & Utilities Corp. as at December 31, 2014 and 2013, and the consolidated results of its operations and its cash flows for the years then ended, in conformity with United States generally accepted accounting principles.

Other matter

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Algonquin Power & Utilities Corp.'s internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated March 16, 2015 expressed an unqualified opinion on Algonquin Power & Utilities Corp.'s internal control over financial reporting.

Ernst & Young LLP

Chartered Professional Accountants,
Licensed Public Accountants
Toronto, Canada
March 16, 2015

EY

A member firm of Ernst & Young Global Limited

INDEPENDENT AUDITORS' REPORT ON INTERNAL CONTROLS UNDER STANDARDS OF THE PUBLIC COMPANY ACCOUNTING OVERSIGHT BOARD (UNITED STATES)

To the Shareholders of Algonquin Power & Utilities Corp.

We have audited Algonquin Power & Utilities Corp.'s internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). Algonquin Power & Utilities Corp.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on Algonquin Power & Utilities Corp.'s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with United States generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Algonquin Power & Utilities Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the COSO criteria.

We also have audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Algonquin Power & Utilities Corp. as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income, equity, and cash flows for the years then ended of Algonquin Power & Utilities Corp. and our report dated March 16, 2015 expressed an unqualified opinion thereon.

Ernst & Young LLP

Chartered Professional Accountants,

Licensed Public Accountants

Toronto, Canada

March 16, 2015

EY

A member firm of Ernst & Young Global Limited

Algonquin Power & Utilities Corp.
Consolidated Balance Sheets

(thousands of Canadian dollars)

	December 31, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 9,273	$ 13,839
Accounts receivable, net (note 4)	188,573	160,636
Natural gas in storage (note 1(g))	31,550	25,609
Supplies and consumables inventory	11,825	7,924
Regulatory assets (note 7)	61,645	26,125
Prepaid expenses	10,431	11,341
Notes receivable (note 8)	2,966	598
Deferred income taxes (note 20)	7,210	19,652
Income taxes receivable (note 20)	568	379
Derivative instruments (note 25)	10,688	9,176
Assets held for sale (note 17)	—	23,927
	334,729	299,206
Property, plant and equipment, net (note 5)	3,278,422	2,708,704
Intangible assets, net (note 6)	54,011	54,416
Goodwill (note 6)	92,328	84,647
Regulatory assets (note 7)	187,699	164,223
Derivative instruments (note 25)	31,782	27,123
Long-term investments (note 8)	43,279	32,746
Deferred income taxes (note 20)	57,065	86,632
Other assets (note 12)	35,100	18,784
	$ 4,114,415	$ 3,476,481

Algonquin Power & Utilities Corp.
Consolidated Balance Sheets

(thousands of Canadian dollars)

	December 31, 2014	December 31, 2013
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 68,540	$ 14,489
Accrued liabilities	199,374	146,338
Dividends payable (note 16)	25,395	17,535
Regulatory liabilities (note 7)	20,590	21,632
Long-term liabilities (note 9)	9,130	8,339
Pension and other post-employment benefits (note 10)	333	305
Other long-term liabilities (note 13)	9,873	7,451
Advances in aid of construction (note 1(o))	1,149	1,239
Derivative instruments (note 25)	5,183	2,492
Environmental obligations (note 23(a)(ii))	19,643	10,111
Preferred shares, Series C (note 11)	1,085	1,038
Liabilities held for sale (note 17)	—	1,471
Income taxes liability (note 20)	3,633	5,159
Deferred credits (note 13)	18,638	7,778
Deferred income taxes (note 20)	3,702	2,308
	386,268	247,685
Long-term liabilities (note 9)	1,270,893	1,247,249
Advances in aid of construction (note 1(o))	79,955	77,697
Regulatory liabilities (note 7)	102,196	101,657
Deferred income taxes (note 20)	130,758	137,153
Derivative instruments (note 25)	40,088	13,729
Deferred credits (note 13)	13,624	17,115
Pension and other post-employment benefits (note 10)	138,602	70,532
Environmental obligation (note 23(a)(ii))	52,662	59,444
Other long-term liabilities (note 13)	33,227	20,492
Preferred shares, Series C (note 11)	17,608	17,767
	1,879,613	1,762,835
Redeemable non-controlling interest (note 3(c))	12,146	—
Equity:		
Preferred shares (note 14(b))	213,805	116,546
Common shares (note 14(a))	1,633,262	1,351,264
Subscription receipts (note 14(a)(iii))	110,503	—
Additional paid-in capital	33,068	7,313
Deficit	(505,305)	(488,406)
Accumulated other comprehensive income (loss) (note 15)	34,213	(31,410)
Total Equity attributable to shareholders of Algonquin Power & Utilities Corp.	1,519,546	955,307
Non-controlling interests	316,842	510,654
Total Equity	1,836,388	1,465,961
Commitments and contingencies (note 23)		
Subsequent events (notes 3(a), 14(c)(iv) and 20)		
	$ 4,114,415	$ 3,476,481

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Operations

(thousands of Canadian dollars, except per share amounts)	Year ended December 31	
	2014	2013
Revenue		
Regulated electricity distribution	$ 206,667	$ 166,156
Regulated gas distribution	446,025	260,424
Regulated water reclamation and distribution	66,419	57,350
Non-regulated energy sales	202,300	180,191
Other revenue	22,149	11,170
	943,560	675,291
Expenses		
Operating	235,984	180,346
Regulated electricity purchased	120,506	97,376
Regulated gas purchased	261,116	148,784
Non-regulated energy purchased	39,264	25,835
Administrative expenses	34,692	23,518
Depreciation of property, plant and equipment	108,974	91,978
Amortization of intangible assets	4,626	4,200
Other amortization	447	(159)
Gain on foreign exchange	(1,112)	(567)
	804,497	571,311
Operating income from continuing operations	139,063	103,980
Interest expense	62,418	53,426
Interest, dividend income and other income	(7,758)	(7,785)
Loss (gain) on sale of assets	(436)	750
Acquisition-related costs	2,552	2,140
Write-down of long-lived assets	8,463	—
Loss (gain) on derivative financial instruments (note 25(b)(iv))	1,375	(5,200)
	66,614	43,331
Earnings from continuing operations before income taxes	72,449	60,649
Income tax expense (note 20)		
Current	3,674	2,526
Deferred	13,133	6,629
	16,807	9,155
Earnings from continuing operations	55,642	51,494
Loss from discontinued operations, net of tax (note 17)	(2,127)	(42,011)
Net earnings	53,515	9,483
Net loss attributable to non-controlling interests (note 19)	(22,186)	(10,813)
Net earnings attributable to shareholders of Algonquin Power & Utilities Corp.	$ 75,701	$ 20,296
Basic net earnings per share from continuing operations (note 21)	$ 0.32	$ 0.28
Basic net loss per share from discontinued operations (note 21)	(0.01)	(0.21)
Basic net earnings per share (note 21)	0.31	0.07
Diluted net earnings per share from continuing operations (note 21)	0.32	0.28
Diluted net loss per share from discontinued operations (note 21)	(0.01)	(0.20)
Diluted net earnings per share (note 21)	$ 0.31	$ 0.07

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Comprehensive Income

(thousands of Canadian dollars)	Year ended December 31	
	2014	2013
Net earnings	$ 53,515	$ 9,483
Other comprehensive income:		
Foreign currency translation adjustment, net of tax recovery of $1,049 and tax expense of $149, respectively (notes 1(v), 25(b)(iii) and 25(c))	100,548	81,597
Change in fair value of cash flow hedge, net of tax expense of $7,638 and $5,103, respectively (note 25(b)(ii))	6,434	17,308
Change in unrealized appreciation in value of available-for-sale investments	1	—
Change in pension and other post-employment benefits, net of tax recovery of $22,446 and tax expense of $10,896, respectively (note 10)	(35,669)	16,727
Other comprehensive income, net of tax	71,314	115,632
Comprehensive income	124,829	125,115
Comprehensive income attributable to the non-controlling interests	7,077	31,362
Comprehensive income attributable to shareholders of Algonquin Power & Utilities Corp.	$ 117,752	$ 93,753

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statement of Equity

(thousands of Canadian dollars)
For the year ended December 31, 2014

	Algonquin Power & Utilities Corp. Shareholders							
	Common shares	Preferred shares	Subscription receipts	Additional paid-in capital	Accumulated deficit	Accumulated OCI	Non-controlling interests	Total
Balance, December 31, 2013	$1,351,264	$116,546	$ —	$ 7,313	$ (488,406)	$ (31,410)	$510,654	$1,465,961
Net earnings (loss)	—	—	—	—	75,701	—	(22,186)	53,515
Redeemable non-controlling interests not included in equity	—	—	—	—	—	—	(289)	(289)
Other comprehensive income	—	—	—	—	—	42,051	29,263	71,314
Dividends declared and distributions to non-controlling interests	—	—	—	—	(75,205)	—	(4,738)	(79,943)
Dividends and issuance of shares under dividend reinvestment plan	17,395	—	—	—	(17,395)	—	—	—
Contributions received from non-controlling interests	—	—	—	—	—	—	9,934	9,934
Issuance of subscription receipts (note 14(a)(iii))	—	—	110,503	—	—	—	—	110,503
Shares issued pursuant to public offering, net of costs (note 14(a)(i))	263,869	—	—	—	—	—	—	263,869
Issuance of common shares under employee share purchase plan	734	—	—	—	—	—	—	734
Share-based compensation	—	—	—	3,203	—	—	—	3,203
Preferred shares Series D, net of costs (note 14(b))	—	97,259	—	—	—	—	—	97,259
Acquisition of non-controlling interest (note 3(g))	—	—	—	22,552	—	23,572	(205,796)	(159,672)
Balance, December 31, 2014	$1,633,262	$213,805	$ 110,503	$33,068	$ (505,305)	$ 34,213	$316,842	$1,836,388

Algonquin Power & Utilities Corp.
Consolidated Statement of Equity

(thousands of Canadian dollars)
For the year ended December 31, 2013

	Algonquin Power & Utilities Corp. Shareholders							
	Common shares	Preferred shares	Subscription receipts	Additional paid-in capital	Accumulated deficit	Accumulated OCI	Non-controlling interests	Total
Balance, December 31, 2012	$1,245,326	$116,546	$ 61,160	$ 5,224	$ (406,143)	$ (104,867)	$484,883	$1,402,129
Net earnings (loss)	—	—	—	—	20,296	—	(10,813)	9,483
Other comprehensive income	—	—	—	—	—	73,457	42,175	115,632
Dividends declared and distributions to non-controlling interests	—	—	—	—	(59,773)	—	(5,591)	(65,364)
Dividends and issuance of shares under dividend reinvestment plan	13,970	—	—	—	(13,970)	—	—	—
Exercise and conversion of subscription receipts	90,464	—	(90,464)	—	—	—	—	—
Issuance of subscription receipts (note 14(a)(iii))	—	—	29,304	—	—	—	—	29,304
Conversion and redemption of convertible debentures	960	—	—	—	—	—	—	960
Issuance of common shares under employee share purchase plan	544	—	—	—	(17)	—	—	527
Share-based compensation expense	—	—	—	2,089	—	—	—	2,089
Preferred shares, Series C (note 11)	—	—	—	—	(18,497)	—	—	(18,497)
Acquisition of non-controlling interest (note 18)	—	—	—	—	(10,302)	—	—	(10,302)
Balance, December 31, 2013	$1,351,264	$116,546	$ —	$ 7,313	$ (488,406)	$ (31,410)	$510,654	$1,465,961

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Cash Flows

(thousands of Canadian dollars)	Year ended December 31 2014	2013
Cash provided by (used in):		
Operating Activities		
Net earnings from continuing operations	$ 55,642	$ 51,494
Adjustments and items not affecting cash:		
Depreciation of property, plant and equipment	108,974	91,978
Amortization of intangible assets	4,626	4,200
Other amortization	1,799	2,891
Deferred taxes	13,133	6,629
Unrealized loss (gain) on derivative financial instruments	3,046	(6,758)
Share-based compensation	3,203	2,000
Cost of equity funds used for construction purposes	(1,910)	(1,786)
Pension and post-employment expense	(2,050)	(302)
Write-down of long-lived assets	8,463	—
Loss on sale of long-lived assets	—	750
Changes in non-cash operating items (note 24)	(1,790)	(47,819)
Changes in non-cash operating items from discontinued operations (note 24)	1,262	36
Cash used in discontinued operations (note 17)	(1,682)	(4,388)
	192,716	98,925
Financing Activities		
Cash dividends on common shares	(57,848)	(52,335)
Cash dividends on preferred shares	(9,503)	(5,400)
Cash contributions from non-controlling interests	11,845	—
Production based cash contributions from non-controlling interest	8,976	1,672
Cash distributions to non-controlling interests	(4,738)	(7,263)
Issuance of common shares, net of costs	261,452	29,983
Proceeds from subscription receipts	110,503	—
Issuance of preferred shares, net of costs	96,271	—
Deferred financing costs	(3,043)	(2,240)
Increase in deferred insurance proceeds & revenue	13,132	—
Acquisition of non-controlling interest	(127,121)	—
Increase in long-term liabilities	236,528	950,346
Decrease in long-term liabilities	(286,552)	(685,472)
Increase (decrease) in advances in aid of construction	(48)	2,299
Increase (decrease) in other long-term liabilities	5,486	(1,574)
	255,340	230,016
Investing Activities		
(Increase) decrease in restricted cash	(11,034)	1,430
Increase in other assets	(2,751)	(3,004)
Distributions received in excess of equity income	264	727
Proceeds from sale of discontinued operations	20,826	24,968
Receipt of principal on notes receivable	280	109
Additions to property, plant and equipment	(432,373)	(158,377)
Acquisitions of long-term investments	(25,432)	—
Acquisitions of operating entities	(8,757)	(239,014)
Proceeds from sale of investment	5,709	3,408
	(453,268)	(369,753)
Effect of exchange rate differences on cash	646	1,529
Decrease in cash and cash equivalents	(4,566)	(39,283)
Cash and cash equivalents, beginning of year	13,839	53,122
Cash and cash equivalents, end of year	$ 9,273	$ 13,839

Supplemental disclosure of cash flow information:	2014	2013
Cash paid during the year for interest expense	$ 60,682	$ 44,185
Cash paid during the year for income taxes	$ 2,571	$ 1,107
Non-cash transactions: Property, plant and equipment acquisitions in accruals	$ 25,568	$ 10,829

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp. ("APUC" or the "Company") is an incorporated entity under the Canada Business Corporations Act. APUC is a diversified generation, transmission and distribution utility company. The distribution business group operates in the United States under the name of Liberty Utilities Co. ("Distribution Group") and provides rate regulated water, electricity and natural gas utility services. The non-regulated generation business group operates under the name Algonquin Power Co. ("Generation Group") and owns or has interests in a portfolio of North American based contracted wind, solar, hydroelectric and natural gas powered generating facilities. The transmission business group operates under the name Liberty Utilities (Pipeline & Transmission) ("Transmission Group") and invests in rate regulated electric transmission and natural gas pipeline systems in the United States and Canada.

1. Significant accounting policies

(a) Basis of preparation

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

(b) Basis of consolidation

The accompanying consolidated financial statements of APUC include the accounts of APUC and its wholly owned subsidiaries and variable interest entities ("VIEs") where the Company is the primary beneficiary (note 1(m)). Intercompany transactions and balances have been eliminated.

(c) Accounting for rate regulated operations

The regulated utility operating companies owned by the Company are subject to rate regulation generally overseen by the public utility commissions of the states in which they operate (the "Regulator"). The Regulator provides the final determination of the rates charged to customers. APUC's regulated utility operating companies are accounted for under the principles of U.S. Financial Accounting Standards Board ("FASB") ASC Topic 980, Regulated Operations ("ASC 980"). Under ASC 980, regulatory assets and liabilities are recorded to the extent that they represent probable future revenues or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate making process. Included in note 7 "Regulatory matters" are details of regulatory assets and liabilities, and their current regulatory treatment.

In the event the Company determines that its net regulatory assets are not probable of recovery, it would no longer apply the principles of the current accounting guidance for rate regulated enterprises and would be required to record an after-tax, non-cash charge (credit) against earnings for any remaining regulatory assets (liabilities). The impact could be material to the Company's reported financial condition and results of operations.

The electric and gas utilities' and the water utilities' accounts are maintained in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission ("FERC") and National Association of Regulatory Utility Commissioners, respectively.

(d) Cash and cash equivalents

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

(e) Restricted cash

Restricted cash represents reserves and amounts set aside pursuant to requirements of various debt agreements and requirements of ISO New England, Inc. Cash reserves segregated from APUC's cash balances are maintained in accounts administered by a separate agent and disclosed separately as restricted cash as part of other assets (note 12) in these consolidated financial statements. APUC cannot access restricted cash without the prior authorization of parties not related to APUC.

(in thousands of Canadian dollars, except as noted and per share amounts)

1. Significant accounting policies (continued)

(f) Accounts receivable

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

(g) Natural gas in storage

Natural gas in storage is reflected at weighted average cost or first-in-first-out as required by regulators and represents natural gas and liquefied natural gas that will be utilized in the ordinary course of business of the gas utilities. Existing rate orders allow the Company to pass through the cost of gas purchased directly to the rate payers along with any applicable authorized delivery surcharge adjustments. Accordingly, the recoverable value of gas in storage does not fall below the cost to the Company (note 7(d)).

(h) Supplies and consumables inventory

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

(i) Property, plant and equipment

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

AFUDC represents the cost of borrowed funds and a return on other funds. Under ASC 980, an allowance for funds used during construction projects that are included in rate base is capitalized. This allowance is designed to enable a utility to capitalize financing costs during periods of construction of property subject to rate regulation. For operations that do not apply regulatory accounting, interest related only to debt is capitalized as a cost of construction in accordance with ASC 835 Interest. The interest capitalized that relates to debt reduces interest expense on the consolidated statements of operations. The AFUDC capitalized that relates to equity funds is recorded as interest, dividend and other income on the consolidated statements of operations.

	2014	2013
Interest capitalized on non-regulated property	**$ 3,584**	$ 669
AFUDC capitalized on regulated property:		
Allowance for borrowed funds	**1,577**	1,055
Allowance for equity funds	**1,910**	1,786
Total	**$ 7,071**	$ 3,510

Improvements that increase or prolong the service life or capacity of an asset are capitalized. Maintenance and repair costs are expensed as incurred. Cost incurred for major expenditures or overhauls that occur at regular intervals over the life of an asset are capitalized and depreciated over the related interval.

(in thousands of Canadian dollars, except as noted and per share amounts)

1. Significant accounting policies (continued)

(i) Property, plant and equipment (continued)

Investment tax credits and government grants are recorded as a reduction to the cost of assets and are amortized at the rate of the related asset as a reduction to depreciation expense. Contributions in aid of construction represent amounts contributed by customers, governments and developers to assist with the funding of some or all of the cost of utility capital assets. It also includes amounts initially recorded as advances in aid of construction (note 1(o)) but where the advance repayment period has expired. These contributions are recorded as a reduction in the cost of utility assets and are amortized at the rate of the related asset as a reduction to depreciation expense.

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

	Range of useful lives		Weighted average useful lives	
	2014	**2013**	**2014**	**2013**
Generation Group				
Renewable	**3 – 60**	3 – 60	**36**	35
Thermal	**3 – 40**	3 – 40	**25**	24
Distribution Group				
Gas	**5 – 100**	5 – 80	**41**	38
Electrical	**5 – 75**	8 – 75	**41**	41
Water & wastewater	**5 – 75**	5 – 50	**39**	39
Equipment	**5 – 50**	5 – 50	**14**	24

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

(j) Intangible assets

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

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

(k) Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the fair value of the net assets acquired. Goodwill is not included in the rate-base on which regulated utilities are allowed to earn a return and is not amortized.

During the fourth quarter of each year, and when indicators of impairment are present, the Company assesses qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit to which goodwill is attributed is less than its carrying amount. If it is more likely than not that a reporting unit's fair value is less than its carrying amount or if a quantitative assessment is elected, the Company calculates the fair value of the reporting unit. The carrying amount of the reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit as a whole exceeds the reporting unit's fair value. An impairment charge is recorded for any excess of the carrying value of the goodwill over the implied fair value. Goodwill is tested for impairment between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount.

1. **Significant accounting policies (continued)**

(l) Impairment of long-lived assets

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

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

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

(m) Variable interest entities

The Company performs analyses to assess whether its operations and investments represent VIEs. To identify potential VIEs, management reviews contracts under leases, long-term purchase power agreements and jointly-owned facilities. VIEs of which the Company is deemed the primary beneficiary are consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the right to receive benefits or the obligation to absorb losses of the entity that could potentially be significant to the entity. In circumstances where APUC is not deemed the primary beneficiary, the VIE is not consolidated (note 8(a)).

The Long Sault Hydroelectric Facility ("Long Sault") is a hydroelectric generating facility in which APUC acquired an interest by way of subscribing to two notes from the original developers. The notes receivable effectively provide APUC the right to 70% after tax cash flows of the facility from 2014 to 2027 and 62.5% thereafter. The Company also has the right to acquire 58% of the equity in the facility at the end of the term of the notes in 2038. Effective December 31, 2013, APUC acquired an equity interest in Long Sault (note 18). APUC has determined that the facility is a VIE. Since the Company is the primary beneficiary, the Long Sault entity is subject to consolidation by the Company. Total net book value of generating assets and long-term debt of Long Sault amounts to $42,689 (2013 - $44,319) and $36,049 (2013 - $37,143), respectively. The Long Sault debt only has recourse over the Long Sault generating assets. The financial performance of Long Sault reflected on the consolidated statements of operations includes non-regulated energy sales of $10,778 (2013 - $10,155), operating expenses and amortization of $3,201 (2013 - $2,391) and interest expense of $3,781 (2013 - $3,632).

The Saint-Damase Wind Powered Generating Facility ("Saint-Damase") is a 24 megawatt ("MW") wind powered generating facility located near St. Damase, Quebec which achieved commercial operation on December 2, 2014. The Company owns a 50% interest in the corporation with the remaining 50% interest held by the Municipality of Saint-Damase. The Company also provided subordinated construction loans to the project. APUC has determined that the corporation holding the facility is a VIE. Since the Company is the primary beneficiary, Saint- Damase is subject to consolidation by the Company. Total net book value of generating assets and third-party long-term debt of Saint-Damase amounts to $69,655 and $23,400, respectively. The financial performance of Saint-Damase reflected on the consolidated statements of operations for its first month of operations in 2014 includes non-regulated energy sales of $440, operating expenses and amortization of $217 and interest expense of $39.

(n) Long-term investments and notes receivable

Investments in which APUC has significant influence but are not controlled are accounted using the equity method. Equity method investments are initially measured at cost including transaction costs and interest when applicable. APUC records its share in the income or loss of its investees in interest, dividend and other income in the consolidated statements of operations.

1. **Significant accounting policies (continued)**

(n) Long-term investments and notes receivable (continued)

Notes receivable are financial assets with fixed or determined payments that are not quoted in an active market. Notes receivable are initially recorded at cost, which is generally face value. Subsequent to acquisition, the notes receivable are recorded at amortized cost using the effective interest method. The Company acquired these notes receivable as long-term investments and does not intend to sell these instruments prior to maturity. Interest from long-term investments is recorded as earned.

If a loss in value of a long-term investment is considered other than temporary, an allowance for impairment on the investment is recorded for the amount of that loss. An allowance for impairment loss on notes receivable is recorded if it is expected that the Company will not collect all principal and interest contractually due. The impairment is measured based on the present value of expected future cash flows discounted at the note's effective interest rate.

(o) Advances in aid of construction

The Company's regulated utilities have various agreements with real estate development companies (the "developers") conducting business within the Company's utility service territories, whereby funds are advanced to the Company by the developers to assist with funding some or all of the costs of the development. These amounts are recorded as Advances in aid of construction on the consolidated balance sheet.

In many instances, developer advances can be subject to refund but the refund is non-interest bearing. Refunds of developer advances are made over periods generally ranging from 10 to 20 years. Advances not refunded within the prescribed period are usually not required to be repaid. After the prescribed period has lapsed, any remaining unpaid balance is transferred to contributions in aid of construction and recorded as an offsetting amount to the cost of property, plant and equipment. In 2014, $4,608 (2013 - $627) was transferred from advances in aid of construction to contributions in aid of construction.

(p) Deferred water rights and customer deposits

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

Customer deposits result from the Company's obligation by state regulators to collect a deposit from customers of its facilities under certain circumstances when services are connected. The deposits are refundable as allowed under the facilities' regulatory agreement. The deposits bear monthly interest and are applied to the customer account after 12 months if the customer is found to be creditworthy.

(q) Pension and other post-employment plans

The Company has established defined contribution pension plans, defined benefit pension plans, and other post-employment benefit ("OPEB") plans for its various employee groups in Canada and the United States. The Company recognizes the funded status of its defined benefit pension plans and OPEB plans on the consolidated balance sheets. The Company's expense and liabilities are determined by actuarial valuations, using assumptions that are evaluated annually as of December 31, including discount rates, mortality, assumed rates of return, compensation increases, turnover rates and healthcare cost trend rates. The impact of modifications to those assumptions and modifications to prior services are recorded as actuarial gains and losses in accumulated other comprehensive income ("AOCI") and amortized to net periodic cost over future periods using the corridor method. The costs of the Company's pension for employees are expensed over the periods during which employees render service and are recognized as part of administrative expenses in the consolidated statements of operations.

1. **Significant accounting policies (continued)**

(r) Asset retirement obligations

The Company recognizes a liability for asset retirement obligations based on the fair value of the liability when incurred, which is generally upon acquisition, construction, development or through the normal operation of the asset. Concurrently, the Company also capitalizes an asset retirement cost, equal to the estimated fair value of the asset retirement obligation, by increasing the carrying value of the related long-lived asset. The asset retirement costs are depreciated over the asset's estimated useful life and are included in depreciation expense on the consolidated statements of operations, or regulatory assets when the amount is recoverable through rates. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the consolidated statements of operations, or regulatory assets when the amount is recoverable through rates. Actual expenditures incurred are charged against the accumulated obligation.

(s) Share-based compensation

The Company has several share-based compensation plans: a share option plan; an employee common share purchase plan ("ESPP"); a deferred share unit ("DSU") plan; and a performance share unit ("PSU") plan. The Company recognizes all employee share-based compensation as a cost in the consolidated financial statements. Equity classified awards are measured at the grant date fair value of the award. The Company estimates grant date fair value of options using the Black-Scholes option pricing model.

(t) Non-controlling interests

Non-controlling interest represents the portion of equity ownership in subsidiaries that is not attributable to the equity holders of the parent company. Non-controlling interests are initially recorded at fair value and subsequently the amount is adjusted for the proportionate share of earnings and other comprehensive income ("OCI") attributable to the non-controlling interests and any dividends or distributions paid to the non-controlling interests.

Certain of the Company's U.S. based wind and solar businesses are organized as limited liability corporations and partnerships and have non-controlling Class A membership equity investors ("Class A partnership units") which are entitled to allocations of earnings, tax attributes and cash flows in accordance with contractual agreements. The share of earnings attributable to the non-controlling interest holders in these subsidiaries is calculated using the Hypothetical Liquidation at Book Value ("HLBV") method of accounting. The HLBV method uses a balance sheet approach, which measures the allocation of income or loss of the Class A partnership units in each period by calculating the change in the amount of distribution the partners would contractually be entitled to based on a hypothetical liquidation of the book value carrying amounts of the entity at the beginning of a reporting period compared to the end of that period (note 19).

If a transaction results in the acquisition of all, or part, of a non-controlling interest in a subsidiary, the acquisition of the non-controlling interest is accounted for as an equity transaction. No gain or loss is recognized in net earnings or comprehensive income as a result of changes in the non-controlling interest, unless a change results in the loss of control by the Company.

Equity instruments subject to redemption upon the occurrence of uncertain events not solely within APUC's control are classified as temporary equity on the consolidated balance sheets. The Company records temporary equity at issuance based on cash received less any transaction costs. At each balance sheet date, the Company reevaluates the classification of its redeemable instruments, as well as the probability of redemption. If the redemption amount is probable or currently redeemable, the Company records the instruments at their redemption value. Increases or decreases in the carrying amount of a redeemable instrument are recorded within accumulated deficit. When the redemption feature lapses or other events cause the classification of an equity instrument as temporary equity to be no longer required, the existing carrying amount of the equity instrument is reclassified to permanent equity at the date of the event that caused the reclassification.

1. **Significant accounting policies (continued)**

(u) Recognition of revenue

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

Revenues related to utility electricity and natural gas sales and distribution are recorded based on metered consumptions by customers, which occur on a systematic basis throughout a month, rather than when the electricity or natural gas is delivered. At the end of each month, the electricity and natural gas delivered to the customers from the date of their last meter read to the end of the month is estimated and the corresponding unbilled revenues are calculated. These estimates of unbilled revenue and sales are based on the ratio of billable days versus unbilled days, amount of electricity or natural gas procured during that month, historical customer class usage patterns, weather, line loss, unaccounted-for gas and current tariffs.

Revenue for the Company's Calpeco Electric System, Peach State and New England Gas Systems is subject to a revenue decoupling mechanism approved by their respective regulator which require to charge approved annual delivery revenues on a systematic basis over the fiscal year. As a result, the difference between delivery revenue calculated based on metered consumption and approved delivery revenue is recorded as a regulatory asset or liability to reflect future recovery or refund, respectively, from customers (note 7(j)).

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

On occasion, a utility is permitted to implement new rates that have not been formally approved by the regulatory commission, which are subject to refund. The Company recognizes revenue based on the interim rate and if needed, establishes a reserve for amounts that could be refunded based on experience for the jurisdiction in which the rates were implemented.

Revenue is recorded net of sale taxes.

During the year, the Company settled insurance claims for business interruption at some of its renewable generation facilities under repairs and as a result recognized revenue of $1,227 (2013 - $6,455).

(v) Foreign currency translation

The Company's reporting currency is the Canadian dollar.

The Company's U.S. operations are determined to have the U.S. dollar as their functional currency since the preponderance of operating, financing and investing transactions are denominated in U.S. dollars. The financial statements of these operations are translated into Canadian dollars using the current rate method, whereby assets and liabilities are translated at the rate prevailing at the balance sheet date, and revenues and expenses are translated using average rates for the period. Unrealized gains or losses arising as a result of the translation of the financial statements of these entities are reported as a component of OCI and are accumulated in a component of equity on the consolidated balance sheets, and are not recorded in income unless there is a complete or substantially complete sale or liquidation of the investment.

1. **Significant accounting policies (continued)**

(w) Income taxes

Income taxes are accounted for using the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. A valuation allowance is recorded against deferred tax assets to the extent that it is considered more likely than not that the deferred tax asset will not be realized. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in earnings in the period that includes the date of enactment. Income tax credits are treated as a reduction to current income tax expense in the year the credit arises or future periods to the extent that realization of such benefit is more likely than not. Investment tax credits are recorded as an offset to the related long-lived asset and are amortized over the estimated life of the asset as credits to income tax expense.

The organizational structure of APUC and its subsidiaries is complex and the related tax interpretations, regulations and legislation in the tax jurisdictions in which they operate are continually changing. As a result, there can be tax matters that have uncertain tax positions. The Company recognizes the effect of income tax positions only if those positions are more likely than not of being sustained. Recognized income tax positions are measured at the largest amount that is greater than 50% likely of being realized. Changes in recognition or measurement are reflected in the period in which the change in judgment occurs.

(x) Financial instruments and derivatives

Accounts receivable and notes receivable are measured at amortized cost and there is no liquid market for these investments. Long-term liabilities, Series C preferred shares and other long-term liabilities are measured at amortized cost using the effective interest method, adjusted for the amortization or accretion of premiums or discounts.

Transaction costs that are directly attributable to the acquisition of financial assets are accounted for as part of the respective asset's carrying value at inception. Transaction costs that are directly attributable to the issuance of financial liabilities, costs of arranging the Company's revolving credit facilities and costs considered as commitment fees paid to financial institutions are recorded in deferred financing costs. Deferred financing costs, premiums and discounts on long-term debt are amortized using the effective interest method while deferred financing costs relating to the revolving credit facilities are amortized on a straight-line basis over the term of the respective revolving credit facility.

The Company uses derivative financial instruments as one method to manage exposures to fluctuations in exchange rates, interest rates and commodity prices. APUC recognizes all derivative instruments as either assets or liabilities in the consolidated balance sheets at their respective fair values. The fair value recognized on derivative instruments executed with the same counterparty under a master netting arrangement are presented on a gross basis on the consolidated balance sheets. The amounts that could net settle are not significant. The Company applies hedge accounting to financial instruments used to manage its foreign currency risk exposure and price risk exposure associated with sales of generated electricity.

For derivatives designated in a cash flow hedge relationship, the effective portion of the change in fair value is recognized as OCI. The ineffective portion is immediately recognized in earnings. The amount recognized in AOCI is reclassified to earnings in the same period as the hedged cash flows affect earnings under the same line item in the consolidated statements of operations as the hedged item. If the hedging instrument no longer meets the criteria for hedge accounting, expires or is sold, terminated, exercised, or the designation is revoked, then hedge accounting is discontinued prospectively. The amount recognized in AOCI is transferred to the consolidated statements of operations in the same period that the hedged item affects earnings. If the forecast transaction is no longer expected to occur, then the balance in AOCI is recognized immediately in earnings.

1. **Significant accounting policies (continued)**

(x) Financial instruments and derivatives (continued)

Foreign currency gain or loss on derivative or financial instruments designated as a hedge of the foreign currency exposure of a net investment in foreign operations, that are effective as a hedge are reported in the same manner as the translation adjustment (in OCI) related to the net investment. To the extent that the hedge is ineffective, such differences are recognized in earnings.

Calpeco Electric System and Granite State Electric System enter into power purchase agreements ("PPA") for load serving requirements. These contracts meet the exemption for normal purchase and normal sales and as such, are not required to be recorded at fair value as derivatives and are accounted for on an accrual basis. Counterparties are evaluated on an ongoing basis for non-performance risk to ensure it does not impact the conclusion with respect to this exemption.

(y) Fair value measurements

The Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs to the extent possible. The Company determines fair value based on assumptions that market participants would use in pricing an asset or liability in the principal or most advantageous market. When considering market participant assumptions in fair value measurements, the following fair value hierarchy distinguishes between observable and unobservable inputs, which are categorized in one of the following levels:

- Level 1 Inputs: Unadjusted quoted prices in active markets for identical assets or liabilities accessible to the reporting entity at the measurement date.
- Level 2 Inputs: Other than quoted prices included in Level 1, inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the asset or liability.
- Level 3 Inputs: Unobservable inputs for the asset or liability used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at measurement date.

(z) Commitments and contingencies

Liabilities for loss contingencies arising from environmental remediation, claims, assessments, litigation, fines, and penalties and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Legal costs incurred in connection with loss contingencies are expensed as incurred.

(aa) Use of estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of these consolidated financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the years presented, management has made a number of estimates and valuation assumptions, including the useful lives and recoverability of property, plant and equipment, intangible assets and goodwill; the recoverability of notes receivable and long-term investments; the recoverability of deferred tax assets; assessments of unbilled revenue; pension and OPEB obligations; timing effect of regulated assets and liabilities; contingencies related to environmental matters; the fair value of assets and liabilities acquired in a business combination; and, the fair value of financial instruments. These estimates and valuation assumptions are based on present conditions and management's planned course of action, as well as assumptions about future business and economic conditions. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

2. Recently issued accounting pronouncements

(a) Recently adopted accounting pronouncements

The FASB issued ASU 2013-11, Income Taxes (Topic 740): Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists. This newly issued accounting standard requires an entity to present an unrecognized tax benefit, or a portion of an unrecognized tax benefit as a reduction to a deferred income tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward, except in some specific situations. The adoption of this standard did not have an impact on the Company's financial position or results of operations.

The FASB issued ASU 2013-10, Derivatives and Hedging (Topic 815): Inclusion of the Fed Funds Effective Swap Rate (or Overnight Index Swap Rate) as a Benchmark Interest Rate for Hedge Accounting Purposes. This newly issued accounting standard permits the Fed Funds Effective Swap Rate (OIS) to be used as a U.S. benchmark interest rate for hedge accounting purposes under Topic 815, in addition to interest rates on direct Treasury obligations of the U.S. government and the London Interbank Offered Rate. The amendments also remove the restriction on using different benchmark rates for similar hedges. The adoption of this standard did not have an impact on the Company's financial position or results of operations.

The FASB issued ASU 2013-04, Liabilities (Topic 405): Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation Is Fixed at the Reporting Date. This newly issued accounting standard provides guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation within the scope of this guidance is fixed at the reporting date, except for obligations addressed within existing guidance in U.S. GAAP. Examples of obligations within the scope of this update include debt arrangements, other contractual obligations, and settled litigation and judicial rulings. The adoption of this standard did not have an impact on the Company's financial position or results of operations.

(b) Recent accounting guidance not yet adopted

The FASB issued ASU 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis, which ends the deferral granted to investment companies from applying the VIE guidance and makes targeted amendments to the current consolidation guidance. Some of the more notable amendments are (1) the identification of variable interests when fees are paid to a decision maker or service provider, (2) the VIE characteristics for a limited partnership or similar entity and (3) the primary beneficiary determination. This ASU may be applied using a modified retrospective approach by recording a cumulative-effect adjustment to equity as of the beginning of the fiscal year of adoption or retrospectively to all prior periods presented in the financial statements. The standard is effective for periods beginning after December 15, 2015. Early adoption is permitted. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

The FASB issued ASU 2015-01, Income Statement: Extraordinary and Unusual Items (Subtopic 225-20), to simplify income statement classification by removing the concept of extraordinary items from U.S. GAAP. As a result, items that are both unusual and infrequent will no longer be separately reported net of tax after continuing operations. This ASU may be applied prospectively or retrospectively to all prior periods presented in the financial statements. The standard is effective for periods beginning after December 15, 2015. Early adoption is permitted, but only as of the beginning of the fiscal year of adoption. The adoption of this standard is not expected to have an impact on the Company's results of operations.

3. Business acquisitions and development projects

(a) Acquisition of New Hampshire Gas

Subsequent to year-end, the Distribution Group completed the acquisition of New Hampshire Gas, a regulated propane gas distribution utility located in Keene, New Hampshire. The New Hampshire Gas System services approximately 1,200 propane gas distribution customers. Total purchase price for the New Hampshire Gas System is approximately U.S. $3,047, subject to certain closing adjustments.

(b) Agreement to acquire Park Water System

On September 19, 2014, the Company entered into an agreement to acquire the regulated water distribution utility Park Water Company ("Park Water System"). Park Water System owns and operates three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in Southern California and Western Montana. Total consideration for the utility purchase is expected to be approximately U.S. $327,000, which includes the assumption of approximately U.S. $77,000 of existing long-term utility debt and is subject to certain working capital and other closing adjustments. Closing of the transaction is subject to certain conditions including state and federal regulatory approval, and is expected to occur in the latter half of 2015.

(c) Development of Bakersfield Solar Project

During the year, the Company constructed a 20 MWac solar powered generating facility located in Kern County, California. As of December 31, 2014, the Company has incurred U.S $56,814 in the development and construction of the solar energy project which is recorded as property, plant and equipment. The facility was placed in service on December 31, 2014. Sales of power to the utility under the power purchase agreement is planned for early 2015.

On August 13, 2014, the Generation Group entered into a definitive partnership agreement with a third-party (the "Tax Investor"). It is anticipated that approximately U.S. $22,800 will be funded by the Tax Investor. With its partnership interest, the Tax Investor will receive the majority of the tax attributes associated with the project. The Tax Equity investment as of December 31, 2014 is U.S. $10,470.

Under certain conditions, the Tax Investor has the right to withdraw from the Bakersfield Solar Project and require the Company to redeem its interests for cash over a contractual payment period. As a result, the Company accounts for this interest as temporary equity and records this interest outside of permanent equity on the consolidated balance sheets as "Redeemable non-controlling interest". The Company records temporary equity at issuance based on cash received less any transaction costs. As of December 31, 2014, transaction costs of $956 have been recorded as a reduction to Redeemable non-controlling interest.

At each balance sheet date, the Company will reevaluate the classification of its redeemable instrument, as well as the probability of redemption. If the redemption amount is probable or currently redeemable, the Company will record the instruments at its redemption value. Increases or decreases in the carrying amount of a redeemable instrument will be recorded within accumulated deficit. Redemption is not considered probable as of December 31, 2014.

(d) Commercial operation of Saint-Damase Wind Facility

Saint-Damase is a 24 MW wind powered generating facility located near St. Damase, Quebec which achieved commercial operation on December 2, 2014. Total net book value of generating assets of Saint-Damase amounts to $69,655. Property, plant and equipment are amortized over the estimated useful life of the assets using the straight-line method. The weighted average useful life of the Saint-Damase Wind Generating Facility is 35 years.

(in thousands of Canadian dollars, except as noted and per share amounts)

3. Business acquisitions and development projects (continued)

(e) Commercial operation of Cornwall Solar Facility

On March 27, 2014, the Cornwall Solar Facility, a 10 MWac solar powered generating facility located near Cornwall, Ontario, commenced commercial operations. The Company invested $41,551 in the development and construction of the solar energy project which is recorded as property, plant and equipment, as well as additional amounts related to development rights and other intangible assets, for a total investment of $47,561. Property, plant and equipment are amortized over the estimated useful life of the assets using the straight-line method. The weighted average useful life of the Cornwall Solar Powered Facility is 33 years.

(f) Acquisition of White Hall Water System

On May 30, 2014, the Distribution Group acquired the assets of the White Hall Water System, a regulated water distribution and wastewater treatment utility located in White Hall, Arkansas. The White Hall Water System serves approximately 1,900 water distribution and 2,400 wastewater treatment customers. Total purchase price for the White Hall Water System assets, adjusted for certain working capital and other closing adjustments, is approximately U.S. $4,499.

(g) Acquisition of non-controlling interest in U.S. Wind farms

On March 31, 2014, the Company acquired the 40% interest in Wind Portfolio SponsorCo, LLC ("Wind Portfolio SponsorCo") from Gamesa Corporación Tecnológica, S.A. for approximately U.S. $115,000. Wind Portfolio SponsorCo indirectly holds the interests in Sandy Ridge, Senate and Minonk Wind acquired in 2012. As a result of the transaction, the Generation Group now owns 100% of Wind Portfolio SponsorCo's Class B partnership units resulting in the elimination of the non-controlling interest in respect of the Class B partnership units of Wind Portfolio SponsorCo as follows:

Elimination of non-controlling interest in Class B partnership units	$	205,796
Non-controlling interest portion of currency translation adjustment recorded to AOCI		(21,029)
Non-controlling interest portion of unrealized gain on cash flow hedges recorded to AOCI		(2,543)
Decrease in deferred income tax asset		(32,551)
Additional paid-in capital		(22,552)
Cash	$	127,121

(h) Acquisition of New England Gas System

On December 20, 2013, the Company acquired certain regulated natural gas distribution utility assets (the "New England Gas System") located in the State of Massachusetts. Total purchase price for the New England Gas System, net of the debt assumed, is $67,010 (U.S. $62,745), including the purchase price adjustment of U.S. $3,108 finalized in Q2 2014.

(in thousands of Canadian dollars, except as noted and per share amounts)

3. **Business acquisitions and development projects (continued)**

(h) Acquisition of New England Gas System (continued)

In 2014, the Company received additional information which was used to refine the estimates for fair value of assets acquired and liabilities assumed. The carrying value of those assets and liabilities were retrospectively adjusted to the amounts detailed in the table below. The key adjustments were an increase to the regulatory asset for pension of U.S. $4,642, a decrease of property, plant and equipment of U.S. $1,190, an increase of the environmental obligation of U.S. $4,408 and an increase of the pension obligation of U.S. $772.

Working capital	$	7,543
Restricted cash		595
Property, plant and equipment		83,365
Regulatory assets		52,601
Other assets		1,221
Long-term debt		(25,349)
Regulatory liabilities		(9,874)
Pension and OPEB		(26,184)
Environmental obligation		(14,933)
Deferred income tax liability, net		(1,158)
Other liabilities		(817)
Total net assets acquired	$	67,010

The determination of the fair value is based upon management's estimates and assumptions with respect to the fair values of the assets acquired and liabilities assumed.

Property, plant and equipment are amortized in accordance with regulatory requirements over the estimated useful life of the assets using the straight-line method. The weighted average useful life of the New England Gas System assets is 31 years.

All costs related to the acquisition have been expensed through the consolidated statements of operations.

The New England Gas System contributed revenue of $91,782 (2013 - $3,582) and net earnings of $10,819 (2013 - $1,153) to the Company's consolidated financial results for 2014.

(i) Acquisition of Shady Oaks Wind Facility

Effective January 1, 2013, the Company acquired the 109.5 MW Shady Oaks wind-powered generating facility ("Shady Oaks Wind Facility"). The purchase agreement provides for final purchase price adjustments based on working capital at the acquisition date, energy generated by the project and basis differences between the relevant node and hub prices which are expected to be finalized in 2015. Changes in measurement of the final purchase price adjustment subsequent to December 31, 2013, the end of the business combination measurement period, are recorded in current period operations. To that effect, a gain of U.S. $1,133 was recognized in 2014.

4. **Accounts receivable**

Accounts receivable as of December 31, 2014 include unbilled revenue of $52,880 (December 31, 2013 - $45,274) from the Company's regulated utilities. Accounts receivable as of December 31, 2014 are presented net of allowance for doubtful accounts of $7,229 (December 31, 2013 - $8,461).

(in thousands of Canadian dollars, except as noted and per share amounts)

5. Property, plant and equipment

Property, plant and equipment consist of the following:

2014

	Cost	Accumulated depreciation	Net book value
Generation Group			
Renewable	$ 1,697,020	$ 217,615	$ 1,479,405
Thermal	130,227	53,131	77,096
Distribution Group			
Water & wastewater	358,520	78,290	280,230
Electricity	347,633	23,659	323,974
Gas	849,136	45,777	803,359
Land	19,347	—	19,347
Equipment and other	119,367	29,526	89,841
Construction in progress			
Generation	82,840	—	82,840
Distribution	122,330	—	122,330
	$ 3,726,420	$ 447,998	$ 3,278,422

2013

	Cost	Accumulated depreciation	Net book value
Generation Group			
Renewable	$ 1,438,229	$ 166,175	$ 1,272,054
Thermal	116,975	43,596	73,379
Distribution Group			
Water & wastewater	303,410	63,807	239,603
Electricity	277,679	16,782	260,897
Gas	682,445	15,769	666,676
Land	8,266	—	8,266
Equipment and other	78,881	29,100	49,781
Construction in progress			
Generation	54,432	—	54,432
Distribution	83,616	—	83,616
	$ 3,043,933	$ 335,229	$ 2,708,704

Renewable generation assets include cost of $155,629 (2013 - $86,774) and accumulated depreciation of $34,013 (2013 - $31,739) related to facilities under capital lease or owned by consolidated VIEs. Depreciation expense of facilities under capital lease was $2,274 (2013 - $2,155).

Investments tax credits, government grants and contributions received in aid of construction of $362 (2013 - $3,098) have been credited to the cost of the distribution assets. Water and wastewater distribution assets include expansion costs of $1,000 on which the Company does not currently earn a return.

(in thousands of Canadian dollars, except as noted and per share amounts)

6. Intangible assets and goodwill

Intangible assets consist of the following:

2014

	Cost	Accumulated amortization	Net book value
Power sales contracts	$ 64,605	$ 33,704	$ 30,901
Customer relationships	31,094	7,984	23,110
	$ 95,699	$ 41,688	$ 54,011

2013

	Cost	Accumulated amortization	Net book value
Power sales contracts	$ 61,430	$ 28,987	$ 32,443
Customer relationships	28,512	6,539	21,973
	$ 89,942	$ 35,526	$ 54,416

Estimated amortization expense for intangible assets for the next two years is $4,750 each year, $3,000 in year three, $2,640 in year four and $2,580 in year five.

Changes in goodwill are as follows:

	Distribution Group
Balance, January 1, 2013	$ 61,459
Business acquisitions	17,260
Adjustments	748
Foreign exchange	5,180
Balance, December 31, 2013	$ 84,647
Foreign exchange	7,681
Balance, December 31, 2014	$ 92,328

7. Regulatory matters

The Company's regulated utility operating companies are subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting policies, issuance of securities, acquisitions and other matters. These utilities operate under cost-of-service regulation as administered by these state authorities. The Company's regulated utility operating companies are accounted for under the principles of ASC 980. Under ASC 980, regulatory assets and liabilities that would not be recorded under U.S. GAAP for non-regulated entities are recorded to the extent that they represent probable future revenues or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate-setting process.

At any given time, the Company can have several regulatory proceedings underway. The financial effects of these proceedings are reflected in the consolidated financial statements based on regulatory approval obtained to the extent that there is a financial impact during the applicable reporting period.

(in thousands of Canadian dollars, except as noted and per share amounts)

7. Regulatory matters (continued)

On March 17, 2014, the Granite State Electric System received a Final Order from the New Hampshire Public Utilities Commission approving a rate increase of U.S. $10,875 consisting of U.S. $9,760 in base rates and an additional U.S. $1,115 for incremental capital expended after the test year. In addition, the Order allows for a one time recovery of rate case expenses of U.S. $390. The new rates were effective as of April 1, 2014 for service rendered on and after July 1, 2013.

On April 18, 2014, the LPSCo Water System received a Final Order from the Arizona Corporation Commission approving a rate increase of U.S. $1,767 in connection with its rate application filed on February 28, 2013. The new rates became effective on May 1, 2014.

In May 2014, the Peach State Gas System received a Final Order from the Georgia Public Service approving an annual revenue increase of U.S. $3,235 in connection with its annual GRAM filing on October 1, 2013. The new rates were effective as of June 1, 2014 for service rendered on and after February 1, 2014.

On December 4, 2014, the Peach State Gas System received a Final Order from the Georgia Public Service approving an annual revenue increase of U.S. $3,680 in connection with its annual GRAM filing on October 1, 2014. The new rates are effective as of February 1, 2015.

Regulatory assets and liabilities consist of the following:

		2014		2013
Regulatory assets				
Environmental costs (a)	$	**102,735**	$	85,029
Pension and post-employment benefits (b)		**65,745**		64,997
Storm costs (c)		**3,080**		5,437
Commodity costs adjustment (d)		**41,502**		15,904
Rate case costs (e)		**4,161**		3,119
Vegetation management		**3,260**		2,297
Debt premium (f)		**4,658**		4,504
Rate adjustment mechanism (j)		**6,207**		28
Asset retirement obligation (g)		**1,682**		1,468
Tax related		**4,350**		2,995
Other		**11,964**		4,570
Total regulatory assets	$	**249,344**	$	190,348
Less current regulatory assets		**(61,645)**		(26,125)
Non-current regulatory assets	$	**187,699**	$	164,223
Regulatory liabilities				
Cost of removal (h)	$	**78,013**	$	68,698
Rate-base offset (i)		**23,427**		25,082
Commodity costs adjustment (d)		**10,389**		17,394
Pension and post-employment benefits (b)		**592**		6,770
Rate adjustment mechanism (j)		**448**		1,681
Storm costs (c)		**1,030**		—
Depreciation adjustment mechanism		**3,518**		—
Tax related		**145**		133
Other		**5,224**		3,531
Total regulatory liabilities	$	**122,786**	$	123,289
Less current regulatory liabilities		**(20,590)**		(21,632)
Non-current regulatory liabilities	$	**102,196**	$	101,657

7. Regulatory matters (continued)

(a) Environmental remediation costs recovery: Actual expenditures incurred for the clean-up of certain former gas manufacturing facilities (note 23 (a)(ii)) are recovered through rates over a period of 7 years and in a jurisdiction are subject to an annual cap.

(b) Pension and post-employment benefits: As part of business acquisitions, the regulators authorized a regulatory asset or liability being set up for the amounts of pension and post-employment benefits that have not yet been recognized in net periodic cost and were presented as AOCI prior to the acquisition. An amount of $28,284 relates to a recent acquisition and was authorized for recognition as an asset by the regulator. Recovery is anticipated to be approved in a final rate order in 2015. The balance is recovered through rates over the future services years of the employees at the time the regulatory asset was set up (an average of 10 years) or consistent with the treatment of OCI under ASC 712 Compensation-Nonretirement Postemployment Benefits and ASC 715 Compensation-Retirement Benefits before the transfer to regulatory asset occurred.

(c) Storm costs: Incurred repair costs resulting from certain storms over or under amounts collected from customers, which are expected to be recovered or refunded through rates.

(d) Commodity costs adjustment: The revenue of the electric and natural gas utilities includes a component which is designed to recover the cost of electricity or natural gas through rates charged to customers. Under deferred energy accounting, to the extent actual natural gas and purchased power costs differ from natural gas and purchased power costs recoverable through current rates, that difference is not recorded on the consolidated statements of operations but rather is deferred and recorded as a regulatory asset or liability on the consolidated balance sheets. These differences are reflected in adjustments to rates and recorded as an adjustment to cost of natural gas or electricity in future periods, subject to regulatory review. Derivatives are often utilized to manage the price risk associated with natural gas purchasing activities in accordance with the expectations of state regulators. The gains and losses associated with these derivatives (note 25 (b)(i)) are recoverable through the commodity costs adjustment.

(e) Rate case costs: The costs to file, prosecute and defend rate case applications are referred to as rate case costs. These costs are capitalized and amortized over the period of rate recovery granted by the regulator.

(f) Debt premium: The value of debt assumed in the acquisition of the New England Gas System has been recorded at fair value in accordance with ASC 805 Business Combinations. The Massachusetts regulator allows for recovery of interest at the coupon rate of the debt and a regulatory asset has been recorded for the difference between the fair value and face value of the debt. The debt premium is recovered over the remaining term of the debt (note 9).

(g) Asset retirement obligation: Asset retirement obligations incurred by the utilities are expected to be recovered through rates.

(h) Cost of removal: The regulatory liability for cost of removal represents amounts that have been collected from ratepayers for costs that are expected to be incurred in the future to retire the utility plant.

(i) Rate-base offset: The regulators imposed a rate-base offset that would reduce the revenue requirement at future rate proceedings. The rate-base offset declines on a straight-line basis over a period of ten years.

(j) Rate adjustment mechanism: Revenue for Calpeco Electric System and Peach State Gas System is subject to a revenue decoupling mechanism approved by their respective regulator which require charging approved annual delivery revenues on a systematic basis over the fiscal year. As a result, the difference between delivery revenue calculated based on metered consumption and approved delivery revenue is recorded as a regulatory asset or liability to reflect future recovery or refund, respectively, from customers. In addition, retroactive rate adjustments for services rendered but collected over a period not exceeding twenty-four months is accrued upon approval of the Final Order.

As recovery of regulatory assets is subject to regulatory approval, if there were any changes in regulatory positions that indicate recovery is not probable, the related cost would be charged to earnings in the period of such determination. The Company earns carrying charges on the regulatory balances related to commodity costs adjustment, rate case costs, vegetation management and storm costs in some jurisdictions.

(in thousands of Canadian dollars, except as noted and per share amounts)

8. Long-term investments

Long-term investments consist of the following:

	2014	2013
Equity-method investees		
50% interest in Odell Wind Project (a)	$ 2,267	$ —
2.5% interest in natural gas pipeline development (b)	1,063	—
32.4% of Class B non-voting shares of Kirkland Lake Power Corp. (c)	1,512	4,851
25% of Class B non-voting shares of Cochrane Power Corporation (c)	—	3,772
50% interest in the Valley Power Partnership	1,253	1,718
Other	640	325
Total	$ 6,735	$ 10,666
Notes receivable		
Development loans (a)	$ 17,582	$ —
Red Lily Senior loan, interest at 6.31% (d)	11,588	11,588
Red Lily Subordinated loan, interest at 12.5% (d)	6,565	6,565
Chapais Énergie, Société en Commandite interest at 10.789%	649	1,928
Silverleaf resorts loan, interest at 15.48% maturing July 2020	2,344	2,149
Other	782	448
	39,510	22,678
Less current portion	(2,966)	(598)
Total	$ 36,544	$ 22,080
Total long-term investments	$ 43,279	$ 32,746

(a) Odell Wind Project

On November 14, 2014, the Company acquired a 50% equity interest in Odell SponsorCo LLC ("Odell SponsorCo"), which indirectly owns a 200 MW construction-stage wind development project ("Odell Wind Project") in the state of Minnesota. The total construction costs of the Odell Wind Project are estimated to be U.S. $322,766.

On the acquisition of the Odell Wind Project by Odell SponsorCo, the two members each contributed U.S. $1,000 to the capital of Odell SponsorCo. Upon execution of third-party construction loan and tax equity documents expected in the second quarter of 2015, each party will contribute another U.S. $23,800 to the capital of Odell SponsorCo. The Company holds an option to acquire the other 50% interest for total contributions, subject to certain adjustments, on commencement of operations, which is expected in late 2015 or early 2016.

As of December 31, 2014, Odell SponsorCo is considered a VIE namely due to the low level of its equity at that point. The Company is not considered the primary beneficiary of Odell SponsorCo as the two members have joint control and all decisions must be unanimous. As such, the Company is accounting for the joint venture as an equity method investment. The Company's maximum exposure to loss is $311,966 as of December 31, 2014.

8. Long-term investments (continued)

(a) Odell Wind Project (continued)

The Company entered into a committed loan and credit support facility with Odell SponsorCo. During construction, the Company is obligated to provide Odell SponsorCo with cash advances and credit support (in the form of letters of credit, escrowed cash, or guarantees) in amounts necessary for the continued development and construction of the Odell Wind Project. The loan bears interest at an annual rate of 8% on outstanding principal amount until commercial operation date and 5% thereafter until maturity date, and the letters of credit are charged an annual fee of 2% on their stated amount. Any loan outstanding to Odell SponsorCo, to the extent not otherwise repaid earlier, is repayable in cash on the fifth anniversary of the availability termination date which is thirty days following the commercial operation date.

As of December 31, 2014, the Company had loaned U.S. $13,159 to Odell SponsorCo for development costs of the Odell Wind Project. No interest revenue was accrued on the loan due to insufficient collateral in Odell SponsorCo. The following credit support was also issued by the Company: a U.S. $15,000 letter of credit on behalf of the Odell Wind Project, to the utility under the PPA; guarantee of the obligations of the Odell Wind Project under the wind turbine supply agreement between Odell SponsorCo and Vestas-American Wind Technology, Inc.; a U.S.$23,800 letter of credit on behalf of Odell SponsorCo, to Enel Kansas, LLC under the purchase and sale agreement. The guarantee obligations are recognized under other long-term liabilities and were valued at U.S. $720 using a probability weighted discounted cash flow (level 3).

(b) Natural Gas Pipeline Development

On November 24, 2014, APUC announced that it plans to participate in the development of Kinder Morgan Inc's proposed Northeast Energy Direct natural gas pipeline project. The Company and Kinder Morgan Operating L.P. "A" formed a new entity ("Northeast Expansion LLC") to undertake the development, construction and ownership of a 30-inch or 36-inch natural gas transmission pipeline to be constructed between Wright, NY and Dracut, MA. The pipeline capacity will be contracted with local distribution utilities, and other customers in the northeast U.S. The project is expected to reach commercial operations by late 2018. Under the agreement, APUC initially subscribed for a 2.5% interest in Northeast Expansion LLC with an opportunity to increase its participation up to 10%. The total capital investment assuming APUC exercises its right to subscribe for 10% of the pipeline is expected be up to U.S. $400,000, depending on the final pipeline configuration and design capacity by the end of 2018. As of December 31, 2014, APUC had invested U.S. $375 in Northeast Expansion LLC. The Company assessed that its interest of 2.5% in a limited liability corporation together with the option to increase its participation to 10% and the commitment from its New Hampshire subsidiary to a firm gas transportation agreement for service on the pipeline facilities provide significant influence. As such, the interest is accounted as an equity method investment.

(c) Kirkland Lake Power Corp. and Cochrane Power Corporation

In September 2014, the Company was informed that future cash flows from its investments in Kirkland Lake Power Corp. ("Kirkland") and Cochrane Power Corporation ("Cochrane") are likely to be significantly reduced in the future based on the current power purchase rates negotiations. As the loss in value of these investments is considered other than temporary, an allowance for impairment of $3,414 and $3,772 on Kirkland and Cochrane, respectively, was recorded in the consolidated statements of operations. The fair value of the investments (level 3) was estimated using cash flow information provided by the investees.

8. Long-term investments (continued)

(d) Red Lily I

The Red Lily I Partnership (the "Partnership") is owned by an independent investor. The Company provides operation and supervision services to the Red Lily I project, a 26.4 MW wind energy facility located in southeastern Saskatchewan.

The Company's investment in Red Lily I is in the form of participation in a portion of the senior debt facility, and a subordinated debt facility to the Partnership.

The senior debt facility consists of two tranches. A third-party lender advanced $27,000 of senior debt to the Partnership as Tranche 1. In 2011, APUC advanced $13,000 of senior debt as Tranche 2 to the Partnership and received a pre-payment of $1,412 in 2012. Another third-party lender has also advanced $4,000 of senior debt Tranche 2 to the Partnership. The Company's senior loan Tranche 2 to the Partnership earns interest at the rate of 6.31% and will mature in 2016. Tranche 1 is being repaid in equal blended monthly payments of principal and interest at a rate of 6.99% based upon a twenty-five year amortization. Both tranches of senior debt are secured by substantially all the assets of the Partnership on a pari passu basis.

The subordinated loan earns an interest rate of 12.5%, and the principal matures in 2036 but is repayable by the Partnership in whole or in part at any time after 2016, without a pre-payment premium. The subordinated loan is secured by substantially all the assets of the Partnership but is subordinated to the senior debt.

A second tranche of subordinated loan for an amount equal to the amounts outstanding on Tranche 2 of the senior debt but no greater than $17,000 will be advanced in 2016 by the Company. The proceeds from this additional subordinated debt are required to be used to repay Tranche 2 of the Partnership's senior debt, including the Company's portion.

In connection with the subordinated debt facility, the Company has been granted an option to subscribe for a 75% equity interest in the Partnership in exchange for the outstanding amount on its subordinated loan of up to $19,500, exercisable for a period of 90 days commencing in 2016. The fair value of the conversion option as of December 31, 2014 and 2013 was determined to be negligible.

The above notes are secured by the underlying assets of the respective facilities.

(in thousands of Canadian dollars, except as noted and per share amounts)

9. Long-term liabilities

Long-term liabilities consist of the following:

	2014	2013
Generation Group		
\$350,000 revolving credit facility, interest rate is equal to bankers' acceptance or LIBOR plus a variable rate as outlined in the credit facility agreement. The current rate is BA or LIBOR plus 1.45%, maturing July 31, 2018.	**\$ 23,400**	\$ 124,570
Algonquin Power Co.: Senior Unsecured Notes: \$200,000 bearing an interest rate of 4.65% maturing February 15, 2022; \$150,000 bearing an interest rate of 4.82% maturing February 15, 2021; \$135,000 bearing an interest rate of 5.50% maturing July 25, 2018. The notes have interest only payments, payable semi-annually in arrears.	**484,553**	284,757
Shady Oaks Wind Facility: Senior Debt: U.S. \$76,000 Chinese Development Bank Corporation loan facility, bearing an interest rate of 6 month LIBOR plus 280 basis points, maturing June 30, 2026. The facility has principal and interest payments, payable semi-annually in arrears.	**88,168**	129,759
Long Sault Hydro Facility: Senior Debt: Bonds bearing an interest rate of 10.21% maturing December 31,2027. The bonds have interest and principal payments, payable monthly in arrears.	**36,048**	37,143
Sanger Thermal Facility: Senior Debt: U.S. \$19,200 California Pollution Control Finance Authority Variable Rate Demand Resource Recovery Revenue Bond Series 1990A, bearing an effective interest rate determined by the remarketing agent. The bond has interest only payments, payable monthly in arrears. The effective interest rate in 2014 was 2.01% (2013 – 1.72%). The bonds were fully repaid on December 31, 2014.	**—**	20,421
Chuteford Hydro Facility: Senior Debt: Bonds bearing an interest rate of 11.6%, maturing April 1, 2020. The bond has principal and interest payments, payable monthly in arrears.	**3,028**	3,417
Distribution Group		
U.S. \$200,000 revolving credit facility, interest rate is equal to LIBOR plus a variable rate as outlined in the credit facility agreement. The current rate is LIBOR plus 1.25%, maturing September 30, 2018.	**23,898**	85,620
Liberty Utilities Co.: Senior Unsecured Notes: U.S. \$ 50,000, bearing an interest rate of 3.51%, maturing July 31, 2017; U.S. \$ 25,000, bearing an interest rate of 3.23%, maturing July 31, 2020; U.S. \$115,000, bearing an interest rate of 4.49%, maturing August 1, 2022; U.S. \$ 15,000, bearing an interest rate of 4.14%, maturing March 13, 2023; U.S. \$ 75,000, bearing an interest rate of 3.86%, maturing July 31, 2023; U.S. \$ 60,000, bearing an interest rate of 4.89%, maturing July 30, 2027; U.S. \$ 25,000, bearing an interest rate of 4.26%, maturing July 31, 2028. The notes have interest only payments, payable semi-annually.	**423,436**	388,214

(in thousands of Canadian dollars, except as noted and per share amounts)

	2014	2013
Calpeco Electric System: Senior Unsecured Notes: U.S. $45,000 bearing an interest rate of 5.19%, maturing December 29, 2020; U.S. $25,000 bearing an interest rate of 5.59%, maturing December 29, 2025. The notes have interest only payments, payable semi-annually in arrears.	**81,207**	74,452
Liberty Water Co: Senior Unsecured Notes: U.S. $50,000 bearing an interest rate of 5.60% $5,000 matures annually beginning June 20, 2016; $25,000 maturing December 22, 2020. The note bears interest payments semi-annually in arrears.	**58,005**	53,180
New England Gas System: First mortgage bonds: U.S. $6,500, bearing an interest rate of 9.44%, maturing February 15, 2020; U.S. $7,000, bearing an interest rate of 7.99%, maturing September 15, 2026; U.S. $6,000, bearing an interest rate of 7.24%, maturing December 15, 2027. The notes have interest only payments, payable semi-annually in arrears.	**27,288**	25,244
Granite State Electric System: Senior unsecured notes: U.S. $5,000, bearing an interest rate of 7.37%, maturing November 1, 2023; U.S. $5,000, bearing an interest rate of 7.94%, maturing July 1, 2025; and, U.S. $5,000, bearing an interest rate of 7.30%, maturing June 15, 2028. The notes have interest only payments, payable semi-annually.	**17,402**	15,954
LPSCo Water System: 1999 and 2001 IDA Bonds bearing interest rates of 5.95% and 6.75% and maturing October 1, 2023 and October 1, 2031, respectively. The bonds have principal and interest payments, payable monthly in arrears.	**12,441**	11,668
Bella Vista Water System: 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.	**1,149**	1,189
	$ 1,280,023	$ 1,255,588
Less: current portion	**(9,130)**	(8,339)
	$ 1,270,893	$ 1,247,249

9. Long-term liabilities (continued)

Certain long-term debt issued at a subsidiary level relating to a specific operating facility is secured by the respective facility with no other recourse to the Company. The loans have certain financial covenants, which must be maintained on a quarterly basis. Noncompliance with the covenants could restrict cash distributions/dividends to the Company from the specific facilities.

Generation Group

On December 31, 2014, the U.S. $19,200 senior debt for the Sanger thermal facility was repaid.

On July 31, 2014, the Company increased the credit available under the senior unsecured revolving credit facility to $350,000 from $200,000. The larger revolving credit facility will be used to provide additional liquidity in support of the Generation Group's development portfolio to be completed over the next three years. The maturity of the revolving credit facility has been extended to July 31, 2018.

On January 17, 2014, the Company issued $200,000 senior unsecured debentures bearing interest at 4.65% and with a maturity date of February 15, 2022. The debentures were sold at a price of $99.864 per $100.00 principal amount. Interest payments are payable on February 15 and August 15 each year, commencing on February 15, 2014. the Company incurred deferred financing costs of $1,568, which are being amortized to interest expense over the term of the loan using the effective interest rate method. Concurrent with the offering, the Company entered into a cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated offering into U.S. dollars. The Company designated the entire notional amount of the cross currency fixed for fixed interest rate swap and related short-term U.S. dollar payables created by the monthly accruals of the swap settlement as a hedge of the foreign currency exposure of its net investment in the Company's U.S. operations. The gain or loss related to the fair value changes of the swap and the related foreign currency gains and losses on the U.S. dollar accruals that are designated as, and are effective as, an economic hedge of the net investment in a foreign operation is reported in the same manner as the translation adjustment (in OCI) related to the net investment (note 25(b)(iii)).

Effective January 1, 2013, concurrent with the acquisition of Shady Oaks Wind Facility (note 3(i)), the Company assumed existing long-term debt of approximately U.S. $150,000. Principal of U.S. $46,000 was repaid in 2014 leaving a balance of U.S. $76,000 outstanding as of December 31, 2014. The semi-annual principal repayment schedule for the following 11.5 years ranges from U.S. $3,000 to U.S. $6,000 with a final repayment in 2026. This debt may be repaid in whole or in part on an interest payment date, annually May 15 or November 15, without penalty.

Distribution Group

On December 20, 2013, in connection with the acquisition of the New England Gas System, the Company assumed first mortgage bonds of U.S. $6,000, bearing an interest rate of 7.24%, maturing December 15, 2027; U.S. $7,000, bearing an interest rate of 7.99%, maturing September 15, 2026; and, U.S. $6,500, bearing an interest rate of 9.44%, maturing February 15, 2020.

On September 30, 2013, the Company increased the maximum availability under its senior unsecured revolving credit facility from U.S. $100,000 to $200,000 to meet future working capital requirements and allow for greater financial flexibility. The revolving credit facility has a maturity date of September 30, 2018.

On July 31, 2013, the Company issued U.S. $125,000 of senior unsecured notes through a private placement in three tranches: U.S. $25,000, bearing an interest rate of 3.23%, maturing July 31, 2020; U.S. $75,000, bearing an interest rate of 3.86%, maturing July 31, 2023; and, U.S. $25,000, bearing an interest rate of 4.26%, maturing July 31, 2028. The proceeds from the private placement financing were used to fund a portion of the acquisition of the Peach State Gas System.

On March 14, 2013, the Company issued U.S. $15,000 of senior unsecured notes through a private placement in connection with the acquisition of the Pine Bluff Water System. The notes bear interest at 4.14% and mature March 13, 2023.

(in thousands of Canadian dollars, except as noted and per share amounts)

9. **Long-term liabilities (continued)**

APUC

On November 19, 2013, APUC increased the maximum availability under its senior unsecured revolving credit facility from U.S. $30,000 to $65,000. The revolving credit facility will be used for general corporate purposes and has a maturity date of November 19, 2016. As of December 31, 2014 and 2013, no amounts were outstanding under this revolving credit facility.

As of December 31, 2014, the Company had accrued $18,770 in interest expense (2013 - $14,057). Interest paid on the long-term liabilities in 2014 was $61,287 (2013 - $49,746).

Principal payments due in the next five years and thereafter are:

	2015	2016	2017	2018	2019	Thereafter	Total
Generation Group	$ 8,599	$ 8,779	$ 11,300	$ 169,822	$ 12,132	$ 424,517	$ 635,149
Distribution Group	531	6,393	64,435	30,349	6,492	536,626	644,826
Total	$ 9,130	$ 15,172	$ 75,735	$ 200,171	$ 18,624	$ 961,143	$1,279,975

10. **Pension and other post-employment benefits**

The Company provides defined contribution pension plans to its employees. The Company's contributions for 2014 were $3,287 (2013 - $2,437).

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

(in thousands of Canadian dollars, except as noted and per share amounts)

10. Pension and other post-employment benefits (continued)

(a) Net pension and OPEB obligation

The following table sets forth the projected benefit obligations, fair value of plan assets, and funded status of the Company's plans as of December 31:

	Pension benefits		OPEB	
	2014	2013	2014	2013
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	$ **178,113**	$ 104,291	$ **45,399**	$ 31,674
Projected benefit obligation assumed from business combination	**1,022**	73,601	**—**	17,943
Modifications to pension plan	**(560)**	81	**—**	—
Service cost	**4,828**	3,273	**2,022**	1,602
Interest cost	**8,549**	4,350	**2,186**	1,508
Actuarial loss (gain)	**39,704**	(11,395)	**14,893**	(8,499)
Benefits paid	**(8,125)**	(3,597)	**(1,255)**	(1,158)
Loss on foreign exchange	**18,432**	7,509	**5,012**	2,329
Projected benefit obligation, end of year	$ **241,963**	$ 178,113	$ **68,257**	$ 45,399
Change in plan asset				
Fair value of plan assets, beginning of year	**139,280**	66,524	**13,395**	10,195
Plan assets acquired in business combination	**—**	57,285	**—**	658
Actual return on plan assets	**6,568**	10,733	**1,176**	1,730
Employer contributions	**5,676**	3,013	**(222)**	1,208
Benefits paid	**(7,414)**	(3,597)	**(1,255)**	(1,157)
Gain on foreign exchange	**12,880**	5,322	**1,201**	761
Fair value of plan assets, end of year	$ **156,990**	$ 139,280	$ **14,295**	$ 13,395
Unfunded status	$ **(84,973)**	$ (38,833)	$ **(53,962)**	$ (32,004)
Amounts recognized in the consolidated balance sheets consists of:				
Current liabilities	**—**	(305)	**(333)**	—
Non-current liabilities	**(84,973)**	(38,528)	**(53,629)**	(32,004)
Net amount recognized	$ **(84,973)**	$ (38,833)	$ **(53,962)**	$ (32,004)

The accumulated benefit obligation for the pension plans was $219,007 and $162,179 as of December 31, 2014 and 2013, respectively.

(in thousands of Canadian dollars, except as noted and per share amounts)

10. Pension and other post-employment benefits (continued)

(a) Net pension and OPEB obligation (continued)

The amounts recognized in AOCI before tax were as follows:

	AOCI	
	Pension	**OPEB**
Balance, January 1, 2013	$ 3,333	$ 821
Current year net actuarial gain	(17,777)	(9,878)
Current year prior service loss	82	—
Amortization of net actuarial loss	(23)	(26)
Balance at December 31, 2013	$ (14,385)	$ (9,083)
Current year net actuarial loss	43,350	14,338
Current year prior service credit	(563)	—
Amortization of net actuarial gain	349	641
Balance at December 31, 2014	$ 28,751	$ 5,896

The net actuarial loss for the defined benefit pension plans and OPEB that will be amortized from AOCI into net periodic benefit cost over the next fiscal year are $1,074 and $356, respectively.

(b) Assumptions

Weighted average assumptions used to determine net benefit cost for 2014 and 2013 were as follows:

	Pension benefits		OPEB	
	2014	**2013**	**2014**	**2013**
Discount rate	**4.55%**	3.68%	**4.60%**	3.69%
Expected return on assets	**7.00%**	5.51%	**5.53%**	5.18%
Rate of compensation increase	**2.97%**	3.13%	**N/A**	N/A
Health care cost trend rate				
Before Age 65			**7.63%**	7.68%
Age 65 and after			**7.63%**	7.68%
Assumed Ultimate Medical Inflation Rate			**5.00%**	4.80%
Year in which Ultimate Rate is reached			**2019**	2019

Weighted average assumptions used to determine net benefit obligation for 2014 and 2013 were as follows:

	Pension benefits		OPEB	
	2014	**2013**	**2014**	**2013**
Discount rate	**3.71%**	4.55%	**3.80%**	4.60%
Rate of compensation increase	**3.01%**	2.97%	**N/A**	N/A
Health care cost trend rate				
Before Age 65			**7.00%**	7.63%
Age 65 and after			**7.00%**	7.63%
Assumed Ultimate Medical Inflation Rate			**5.00%**	5.00%
Year in which Ultimate Rate is reached			**2019**	2019

(in thousands of Canadian dollars, except as noted and per share amounts)

10. Pension and other post-employment benefits (continued)

(b) Assumptions (continued)

The Company used the new mortality tables (RP-2014) and the mortality improvement scale (MP-2014) that were recently released by the Society of Actuaries in the current year assumptions. This change resulted in an increase to the pension and OPEB obligations of approximately U.S. $16,500.

In selecting an assumed discount rate, the Company uses a modeling process that involves selecting a portfolio of high-quality corporate debt issuances (AA- or better) whose cash flows (via coupons or maturities) match the timing and amount of the Company's expected future benefit payments. The Company considers the results of this modeling process, as well as overall rates of return on high-quality corporate bonds and changes in such rates over time, to determine its assumed discount rate. The rate of return assumptions are based on projected long-term market returns for the various asset classes in which the plans are invested, weighted by the target asset allocations.

The effect of a one percent change in the assumed health care cost trend rate ("HCCTR") for 2014 is as follows:

		2014
Effect of a 1 percentage point increase in the HCCTR on:		
Year-end benefit obligation	$	10,998
Total service and interest cost		623
Effect of a 1 percentage point decrease in the HCCTR on:		
Year-end benefit obligation	$	(8,664)
Total service and interest cost		(503)

(c) Benefit costs

The following table lists the components of net benefit costs for the pension plans and OPEB recorded as part of operating expenses in the consolidated statements of operations. The employee benefit costs related to businesses acquired are recorded in the consolidated statements of operations from the date of acquisition.

	Pension benefits		OPEB	
	2014	2013	2014	2013
Service cost	**$ 4,828**	$ 3,273	**$ 2,022**	$ 1,602
Interest cost	**8,549**	4,350	**2,186**	1,508
Expected return on plan assets	**(10,018)**	(4,160)	**(628)**	(602)
Amortization of net actuarial loss (gain)	**(346)**	23	**(641)**	26
Net benefit cost	**$ 3,013**	$ 3,486	**$ 2,939**	$ 2,534

(in thousands of Canadian dollars, except as noted and per share amounts)

10. Pension and other post-employment benefits (continued)

(d) Plan assets

The Company's investment strategy for its pension and post-employment plan assets is to maintain a diversified portfolio of assets with the primary goal of meeting long-term cash requirements as they become due.

The Company's target asset allocation is as follows:

Asset Class	Target (%)	Range (%)
Equity securities	74%	49.7%-78%
Debt securities	26%	21.9%-50.3%
Other	—%	0%-0.5%

The fair values of investments as of December 31, 2014, by asset category, are as follows:

Asset Class	Level 1	Percentage
Equity securities	122,943	72%
Debt securities	47,771	28%
Other	570	—%

As of December 31, 2014, the funds do not hold any material investments in APUC.

(e) Cash flows

The Company expects to contribute $4,289 to its pension plans and $2,021 to its post-employment benefit plans in 2015.

The expected benefit payments over the next ten years are as follows:

	2015	2016	2017	2018	2019	2020-2024
Pension plan	$ 9,933	$ 10,471	$ 11,099	$ 11,709	$ 12,234	$ 69,107
OPEB	2,157	2,416	2,697	2,908	3,060	19,472

(in thousands of Canadian dollars, except as noted and per share amounts)

11. Mandatorily redeemable Series C preferred shares

Effective January 1, 2013, the Company issued 100 redeemable Series C preferred shares in exchange for Class B limited partnership units issued by the St. Leon Wind Energy LP ("St. Leon LP"), a subsidiary of the Company and the legal owner of the St. Leon Wind Facility (note 18). Thirty-six of the Series C preferred shares are owned by related parties controlled by executives of the Company. The preferred shares are mandatorily redeemable in 2031 for $53,400 per share (fifty-three thousand and four hundred dollars per share) and have a contractual cumulative cash dividend paid quarterly until the date of redemption based on a prescribed payment schedule detailed below. As these shares are mandatorily redeemable for cash, they are accounted for as liabilities in the consolidated financial statements. The cumulative dividends are indexed in proportion to the increase in CPI over the term of the shares. The dividend is intended to approximate the distributions that otherwise would have accrued to holders of Class B limited partnership units. The Series C preferred shares are convertible into common shares at the option of the holder and the Company, at any time after May 20, 2031 and before June 19, 2031, at a conversion price of $53,400 per share.

The Series C preferred shares were initially measured at their estimated fair value of $18,497 based on the present value of the expected contractual cash flows including dividends and redemption amount, discounted at a rate of 5.0%. The recognition of the initial fair value of $18,497 resulted in an adjustment to equity of the shareholders of the Company as the Class B limited partnership units had a nominal carrying amount prior to the exchange. The Series C preferred shares are accounted for under the effective interest method, resulting in accretion of interest expense over the term of the shares. Dividend payments are recorded as a reduction of the Series C preferred share carrying value.

Estimated dividend payments due in the next five years and dividend and redemption payments thereafter are:

2015	$	1,077
2016		946
2017		895
2018		1,125
2019		1,334
Thereafter to 2031		19,525
Redemption amount		5,340
		30,242
Less amounts representing interest		(11,549)
		18,693
Less current portion		(1,085)
	$	17,608

12. Other assets

Other assets consist of the following:

		2014		2013
Restricted cash	$	**18,702**	$	6,021
Deferred financing costs		**10,732**		9,011
Other		**5,666**		3,752
	$	**35,100**	$	18,784

(in thousands of Canadian dollars, except as noted and per share amounts)

13. Other long-term liabilities and Deferred credits

Other long-term liabilities consist of the following:

	2014	2013
Asset retirement obligation	**$ 13,884**	$ 9,508
Customer deposits	**11,713**	8,774
Provision for injury and damages	**1,173**	1,215
Deferred water rights inducement	**2,683**	2,764
Contingent consideration	**1,202**	1,102
Other	**12,445**	4,580
	43,100	27,943
Less current portion	**(9,873)**	(7,451)
	$ 33,227	$ 20,492

The asset retirement obligation mainly relates to legal requirements to: (i) remove wind farm 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 sections of gas main are 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. During the year, APUC recorded additional asset retirement obligation of $2,570 (2013 - $1,651) for newly constructed renewable generation facilities.

Deferred credits consist of the following:

	2014	2013
Deferred tax credit (note 20)	**$ 19,130**	$ 24,893
Deferred insurance proceeds	**12,190**	—
Deferred revenue	**942**	—
	$ 32,262	$ 24,893
Less: current portion	**(18,638)**	(7,778)
	$ 13,624	$ 17,115

Insurance proceeds received for some renewable generation facilities under repairs are deferred until they are virtually certain of being realized.

14. Shareholders' capital

(a) Common shares

Number of common shares:

	2014	2013
Common shares, beginning of year	**206,348,985**	188,763,486
Public offering (i)	**29,444,000**	—
Conversion and redemption of convertible debentures (ii)	**—**	150,816
Conversion of subscription receipts (iii)	**—**	15,223,016
Issuance of shares under the dividend reinvestment (iv) and employee share purchase plans ((c)(ii))	**2,356,483**	2,211,667
Common shares, end of year	**238,149,468**	206,348,985

14. Shareholders' capital (continued)

(a) Common shares (continued)

Authorized

APUC is authorized to issue an unlimited number of common shares. The holders of the common shares are entitled to dividends if, as and when declared by the Board of Directors (the "Board"); to one vote per share at meetings of the holders of common shares; and upon liquidation, dissolution or winding up of APUC to receive pro rata the remaining property and assets of APUC; subject to the rights of any shares having priority over the common shares.

On April 23, 2013, the Company's shareholders renewed its shareholders' rights plan (the "Rights Plan"). The Rights Plan has a term of three years. Under the Rights Plan, one right is issued with each issued share of the Company. The rights remain attached to the shares and are not exercisable or separable unless one or more certain specified events occur. If a person or group acting in concert acquires 20 percent or more of the outstanding shares (subject to certain exceptions) of the Company, the rights will entitle the holders thereof (other than the acquiring person or group) to purchase shares at a 50 percent discount from the then current market price. The rights provided under the Rights Plan are not triggered by any person making a "Permitted Bid", as defined in the Rights Plan.

(i) Public offering

In December 2014, APUC issued 10,055,000 common shares at $9.95 per share pursuant to a public offering for proceeds of $100,047, before issuance costs of $4,243 or $3,021 net of taxes.

In September 2014, APUC issued 19,389,000 common shares at $8.90 per share pursuant to a public offering for proceeds of $172,562, before issuance costs of $7,648 or $5,719 net of taxes.

(ii) Conversion and redemption of convertible debentures

In 2013, $960 of Series 3 Debentures were redeemed for 150,816 common shares of APUC.

(iii) Subscription receipts

On December 29, 2014, the Company received total proceeds of $77,503 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 acquisition (note 8(a)). At any time after the earlier of commencement of operations of the Odell Wind Project or November 14, 2015, Emera may elect to convert the subscription receipts for no additional consideration on a one-for-one basis into common shares. In the event that Emera has not elected to convert the subscription receipts by November 14, 2016, they will automatically convert into common shares.

On December 29, 2014, the Company received total proceeds of $33,000 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 (note 3(b)). At any time after the earlier of the Park Water System acquisition or December 29, 2015, Emera may elect to convert the subscription receipts for no additional consideration on a one-for-one basis into common shares. In the event that Emera has not elected to convert the subscription receipts by December 29, 2016, they will automatically convert into common shares.

On March 26, 2013, in connection with the acquisition of the Peach State Gas system, the Company issued 3,960,000 common shares at a price of $7.40 per share for total proceeds of $29,304 pursuant to a subscription receipt agreement with Emera.

On February 14, 2013, 11,263,016 subscription receipts issued in 2012 were exercised by Emera and the Company issued 11,263,016 common shares in exchange.

14. Shareholders' capital (continued)

(a) Common shares (continued)

(iv) Dividend reinvestment plan

The Company has a common shareholder dividend reinvestment plan, which provides an opportunity for shareholders to reinvest dividends for the purpose of purchasing common shares. Additional common shares acquired through the reinvestment of cash dividends are purchased in the open market or are issued by APUC at a discount of up to 5% from the average market price, all as determined by the Company from time to time. Subsequent to year-end, APUC issued an additional 706,680 common shares under the dividend reinvestment plan.

(b) Preferred shares

APUC is authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board. On November 9, 2012, APUC issued 4,800,000 Series A preferred shares, at a price of $25 per share, for aggregate proceeds of $120,000 before issuance cost of $4,700 or $3,454 net of tax.

The holders of preferred shares are entitled to receive fixed cumulative preferential dividends at an annual rate of $1.125 per share, payable quarterly, as and when declared by the Board. The Series A preferred shares yield 4.5% annually for the initial six-year period up to, but excluding December 31, 2018, with the first dividend payment occurring December 31, 2012. The dividend rate will reset on December 31, 2018, and every five years thereafter at a rate equal to the then five-year Government of Canada bond yield plus 2.94%. The Series A preferred shares are redeemable at $25 per share at the option of the Company on December 31, 2018, and on December 31 of every fifth year thereafter. The holders of Series A preferred shares have the right to convert their shares into Cumulative Floating Rate preferred shares, Series B (the "Series B preferred shares"), subject to certain conditions, on December 31, 2018, and on December 31 of every fifth year thereafter. The Series B preferred shares carry the same features as the Series A preferred shares, except that holders will be entitled to receive quarterly floating-rate cumulative dividends, as and when declared by the Board, at a rate equal to the then ninety-day Government of Canada treasury bill yield plus 2.94%. The holders of Series B preferred shares will have the right to convert their shares back into Series A preferred shares on December 31, 2018, and on December 31 of every fifth year thereafter. The Series A preferred shares and the Series B preferred shares do not have a fixed maturity date and are not redeemable at the option of the holders thereof.

On January 1, 2013, the Company issued 100 redeemable Series C preferred shares in exchange for Class B limited partnership units issued by the St Leon LP. The mandatorily redeemable Series C preferred shares are recorded as a liability on the consolidated balance sheets (note 11).

On March 5, 2014, APUC issued 4,000,000 Series D preferred shares, at a price of $25 per share, for aggregate proceeds of $100,000 before issuance costs of $3,729 or $2,741 net of tax.

The holders of the Series D preferred shares are entitled to receive fixed cumulative preferential dividends at an annual rate of $1.25 per share, payable quarterly, as and when declared by the Board. The Series D preferred shares yield 5.0% annually for the initial five-year period up to, but excluding March 31, 2019, with the first dividend payment occurring June 30, 2014. The dividend rate will reset on March 31, 2019, and every five years thereafter at a rate equal to the then five-year Government of Canada bond yield plus 3.28%. The Series D preferred shares are redeemable at $25 per share at the option of the Company on March 31, 2019, and on March 31 of every fifth year thereafter. The holders of Series D preferred shares have the right to convert their shares into Cumulative Floating Rate preferred shares, Series E (the "Series E preferred shares"), subject to certain conditions, on March 31, 2019, and on March 31 of every fifth year thereafter. The Series E preferred shares carry the same features as the Series D preferred shares, except that holders will be entitled to receive quarterly floating-rate cumulative dividends, as and when declared by the Board, at a rate equal to the then ninety-day Government of Canada treasury bill yield plus 3.28%. The holders of Series E preferred shares will have the right to convert their shares back into Series D preferred shares on March 31, 2019, and on March 31 of every fifth year thereafter. The Series D preferred shares and the Series E preferred shares do not have a fixed maturity date and are not redeemable at the option of the holders thereof.

(in thousands of Canadian dollars, except as noted and per share amounts)

14. Shareholders' capital (continued)

(c) Share-based compensation

For the year ended December 31, 2014, APUC recorded $3,248 (2013 - $2,046) in total share-based compensation expense detailed as follows:

	2014	2013
Stock options	**$ 1,931**	$ 1,687
Directors deferred share units	**273**	155
Employee share purchase	**116**	75
Performance share units	**928**	129
Total share-based compensation	**$ 3,248**	$ 2,046

The compensation expense is recorded as part of administrative expenses in the consolidated statements of operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As of December 31, 2014, total unrecognized compensation costs related to non-vested options and performance share unit were $2,084 and $2,380, respectively, and are expected to be recognized over a period of 1.71 years and 1.61, respectively.

(i) Stock option plan

The Company's stock option plan (the "Plan") permits the grant of share options to key officers, directors, employees and selected service providers. The aggregate number of shares that may be reserved for issuance under the Plan must not exceed 10% of the number of Shares outstanding at the time the options are granted. The number of shares subject to each option, the option price, the expiration date, the vesting and other terms and conditions relating to each option shall be determined by the Board from time to time. Dividends on the underlying shares do not accumulate during the vesting period. Option holders may elect to surrender any portion of the vested options which is then exercisable in exchange for the "In-the-Money Amount". In accordance with the Plan, the "In-The-Money Amount" represents the excess, if any, of the market price of a share at such time over the option price, in each case such "In-the-Money" amount being payable by the Company in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards.

In the case of qualified retirement, the Board may accelerate the vesting of the unvested options then held by the optionee at the Board's discretion. All vested options may be exercised within ninety days after retirement. In the case of death, the options vest immediately and the period over which the options can be exercised is one year. In the case of disability, options continue to vest and be exercisable in accordance with the terms of the grant and the provisions of the plan. Employees have up to thirty days to exercise vested options upon resignation or termination.

The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date. The Company determines the fair value of options granted using the Black-Scholes option-pricing model. The risk-free interest rate is based on the zero-coupon Canada Government bond with a similar term to the expected life of the options at the grant date. Expected volatility was estimated based on the adjusted historical volatility of the Company's shares. The expected life was estimated to equal the contractual life of the options. The dividend yield rate was based upon recent historical dividends paid on APUC shares.

The following assumptions were used in determining the fair value of share options granted:

	2014	2013
Risk-free interest rate	**1.97%**	1.61%
Expected volatility	**38%**	37%
Expected dividend yield	**3.84%**	3.83%
Expected life	**8 years**	8 years
Weighted average grant date fair value per option	**$ 2.00**	$ 2.00

(in thousands of Canadian dollars, except as noted and per share amounts)

14. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(i) Stock option plan (continued)

Stock option activity during the period is as follows:

	Number of awards		Weighted average exercise price	Weighted average remaining contractual term (years)		Aggregate intrinsic value
Balance at January 1, 2013	3,750,727	$	5.25	6.07	$	5,939
Granted	816,402		7.72	8.00		—
Balance at December 31, 2013	4,567,129	$	5.70	5.45	$	7,814
Granted	969,998		7.95	8.00		—
Balance at December 31, 2014	5,537,127	$	6.09	4.96	$	19,648
Exercisable at December 31, 2014	3,601,647	$	5.33	4.20	$	15,531

(ii) Employee share purchase plan

Under the Company's employee share purchase plan ("ESPP"), eligible employees may have a portion of their earnings withheld to be used to purchase the Company's common shares. The Company will match (a) 20% of the employee contribution amount for the first five thousand dollars per employee contributed annually and 10% of the employee contribution amount for contributions over five thousand dollars up to ten thousand dollars annually, for Canadian employees, and (b) 15% of the employee contribution amount for the first fifteen thousand dollar per employee contributed annually, for U.S. employees. 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 the Company's option, the common shares may be (i) issued to participants from treasury at the average share price or (ii) acquired on behalf of participants by purchases through the facilities of the TSX by an independent broker. The aggregate number of common shares reserved for issuance from treasury by APUC under the ESPP shall not exceed 2,000,000 common shares.

The Company uses the fair value based method to measure the compensation expense related to the Company's contribution. For the year ended December 31, 2014, a total of 93,598 common shares (2013 - 85,410) were issued to employees under the ESPP.

(iii) Directors deferred share units

Under the Company's Deferred Share Unit Plan, non-employee directors of the Company may elect annually to receive all or any portion of their compensation in DSUs in lieu of cash compensation. Directors' fees are paid on a quarterly basis and at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one of the Company's common shares. Dividends accumulate in the DSU account and are converted to DSUs based on the market value of the shares on that date. DSUs cannot be redeemed until the director retires, resigns, or otherwise leaves the Board. The DSUs provide for settlement in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards. As of December 31, 2014, 110,241 (2013 - 74,786) DSUs were outstanding pursuant to the election of the directors to defer a percentage of their director's fee in the form of DSUs.

(in thousands of Canadian dollars, except as noted and per share amounts)

14. Shareholders' capital (continued)

(c) Share-based compensation (continued)

(iv) Performance share units

The Company offers a performance share unit plan to its employees as part of the Company'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 and will be calculated 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 184% 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 PSUs provide for settlement in cash or shares at the election of the Company. During the second quarter, the Company settled 22,665 vested performance share units ("PSUs") for $162 in cash. At the annual general meeting held on June 18, 2014, the shareholders approved a maximum of 500,000 common shares issuable from Treasury to settle PSUs. With the ability to issue shares from Treasury or purchase shares on the market, the Company expects to settle the remaining PSUs in common shares. As a result, the PSUs continue to be accounted for as equity awards.

Compensation expense associated with PSUs is recognized rateably over the performance period and assumes that performance goals will be achieved at 100%. If goals met differ, compensation cost recognized is adjusted to reflect the performance conditions achieved.

A summary of the PSUs follows:

	Number of awards	Weighted Average Grant-Date Fair Value	Weighted Average Remaining Contractual Term (years)	Aggregate intrinsic value
Balance at January 1, 2013	83,483	$ 6.58	1.80	$ 571
Granted	5,537	6.79	1.23	41
Exercised	(20,640)	6.70	—	(151)
Forfeited	(2,185)	6.70	—	(16)
Balance at December 31, 2013	66,195	$ 6.57	0.62	$ 486
Granted, including dividends	407,962	8.22	3.00	3,333
Exercised	(22,665)	6.13	—	(185)
Forfeited	(11,406)	8.22	—	(93)
Balance at December 31, 2014	440,086	$ 6.57	1.81	$ 439
Exercisable at December 31, 2014	42,097	$ 6.86	—	$ 486

(in thousands of Canadian dollars, except as noted and per share amounts)

15. Accumulated other comprehensive income (loss)

Accumulated other comprehensive income (loss) consists of the following balances, net of tax:

	Foreign currency cumulative translation	Unrealized gain (loss) on cash flow hedges	Net change on available-for-sale investments	Pension and post-employment actuarial changes	Total
Balance, January 1, 2013	$(105,957)	$ 3,596	$ —	$ (2,506)	$ (104,867)
OCI before reclassifications	48,486	10,357	—	16,698	75,541
Amounts reclassified	—	(2,113)	—	29	(2,084)
Net current period OCI	48,486	8,244	—	16,727	73,457
Balance, December 31, 2013	$ (57,471)	$ 11,840	$ —	$ 14,221	$ (31,410)
OCI (loss) before reclassifications	65,303	6,993	519	(35,396)	37,419
Amounts reclassified	—	5,423	(518)	(273)	4,632
Net current period OCI (loss)	$ 65,303	$ 12,416	$ 1	$ (35,669)	$ 42,051
Acquisition of non-controlling interest	21,029	2,543	—	—	23,572
Balance, December 31, 2014	$ 28,861	$ 26,799	$ 1	$ (21,448)	$ 34,213

Amounts reclassified from accumulated other comprehensive income (loss) for unrealized gain (loss) on cash flow hedges affected revenue from non-regulated energy sales while those for pension and post-employment actuarial changes affected administrative expenses.

16. Cash dividends

All dividends of the Company are made on a discretionary basis as determined by the Board. For the year ended December 31, 2014, the Company declared dividends to shareholders on common shares totaling $82,898 (2013 - $68,291) or $0.3695 per common share (2013 - $0.3325 per common share). The Board declared a dividend on the Company's common shares of U.S. $0.0875 per share payable on January 15, 2015 to the shareholders of record on December 31, 2014.

For the year ended December 31, 2014, the Company declared and paid dividends to Series A preferred shareholders totaling $5,400 (2013 - $5,400) or $1.125 per Series A preferred share (2013 - $1.1250 per Series A preferred share).

For the year ended December 31, 2014, the Company declared and paid dividends to Series D preferred shareholders totaling $4,103 (2013 - $nil) or $1.0257 per Series D preferred share (2013 - $nil per Series D preferred share).

17. Divestitures

(a) EFW Thermal Facility

During 2013, the Company initiated a strategic review of the Company's business plan and opportunities available for its Energy From Waste Thermal Facility ("EFW Thermal Facility") and Brampton Cogeneration Inc. ("BCI Thermal Facility"). As a result of the review, the Company decided to sell the facilities. In 2013, the net assets of the EFW and BCI were written down to their estimated fair value less cost of sale, which resulted in a write-down of the net assets of $56,851 before tax, or $42,538 net of tax of $14,313. The Company sold the EFW and BCI Thermal Facilities on April 4, 2014. These assets were part of the Generation: Thermal reporting segment.

(in thousands of Canadian dollars, except as noted and per share amounts)

17. Divestitures (continued)

(b) Sale of U.S. Hydro facilities

On June 29, 2013, the Company sold 9 small U.S. hydroelectric generating facilities that were no longer considered strategic to the ongoing operations of the Company, for gross proceeds of U.S. $23,400 for a gain on sale of U.S. $960, net of tax recovery of U.S. $1,605. On June 16, 2014, the Company sold its final small U.S. hydroelectric generating facility for U.S. $3,600. These assets were part of the Generation: Renewable reporting segment.

(c) Results from discontinued operations

The assets of the EFW, BCI Thermal Facilities and the small U.S. hydroelectric generating facilities were presented as assets held for sale on the 2013 consolidated balance sheet and the operating results from these facilities are disclosed as discontinued operations in the 2014 and 2013 consolidated financial statements.

The summary of operating results and cash flows from discontinued operations for the years ended December 31 is as follows:

	2014	2013
Non-regulated energy sales	$ **2,174**	$ 9,327
Waste disposal fees	**2,233**	8,160
Other and interest income	**63**	336
Operating and administrative expenses	**(5,284)**	(19,720)
Foreign exchange	**111**	80
Depreciation of property, plant and equipment	**—**	(2,483)
Interest expense	**(19)**	(58)
Gain (loss) on sale of assets	**(960)**	1,016
Write-off of assets	**(1,971)**	(57,160)
Non-cash gain on sale of assets	**105**	—
Deposit on sale	**143**	—
Loss from discontinued operations, before income taxes	**(3,405)**	(60,502)
Income tax recovery	**1,278**	18,491
Loss from discontinued operations, net of income taxes	$ **(2,127)**	$(42,011)
Add:		
Depreciation of property, plant and equipment	**—**	2,483
Deposit on sale	**(143)**	—
Write-off of assets	**1,971**	57,160
Non-cash gain on sale of assets	**(105)**	—
Incurred closing costs on disposal of assets	**—**	(2,916)
Contingent liability	**—**	(613)
Income tax recovery	**(1,278)**	(18,491)
Cash used in discontinued operations	$ **(1,682)**	$ (4,388)

(in thousands of Canadian dollars, except as noted and per share amounts)

17. Divestitures (continued)

(c) Results from discontinued operations (continued)

Assets held-for-sale as of December 31, were as follows:

	2014	2013
Property, plant and equipment	$ —	$ 21,193
Accounts receivable and prepaid expenses	—	2,734
Total assets held for sale, current	$ —	$ 23,927

Liabilities held for sale as of December 31, were as follows:

	2014	2013
Accounts payable and accrued liabilities	$ —	$ 1,471

18. Related party transactions

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

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

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

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

Due to and from related parties

Effective December 31, 2013, APUC paid the Parties $1,829 in connection with outstanding fees and the Parties paid APUC $812 in connection with reimbursement of expenses. As at December 31, 2014, $47 (2013 - $47) remains due from Algonquin Power Systems Ltd., a corporation partially owned by the Senior Executives.

Equity interests in Rattle Brook, Long Sault, BCI

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

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

18. Related party transactions (continued)

Equity interests in Rattle Brook, Long Sault, BCI (continued)

Effective December 31, 2013, APUC acquired the Parties' shares of Algonquin Power Corporation Inc. ("APC") which owns the partnership interest in the 18 MW Long Sault Rapids hydroelectric facility and the partnership interest in the Brampton cogeneration plant for an amount equal to $3,780. As APUC already consolidates Long Sault as a VIE, the acquisition of this partnership interest was treated as an equity transaction. The payment resulted in an adjustment to deferred tax liability of $10,692 in regards to tax attributes acquired with the partnership interests and an adjustment of $14,601 to equity of the shareholders of the Company as the partnership interests had a nominal carrying amount prior to the exchange.

In addition, APUC sold its 45% interest in the 4 MW Rattle Brook hydroelectric facility to the Parties for gross proceeds $3,408 for a loss on sale, net of tax of $422.

APUC earned a fee of $400 from APC during the year ended December 31, 2013 related to settlement of the related party transactions.

St. Leon LP Units

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

On January 1, 2013, the Company issued 100 redeemable Series C preferred shares and exchanged such shares for the 100 Class B limited partnership units (note 11) including 36 units held indirectly by Senior Executives. The Series C preferred shares provide dividends identical to what is expected from the Class B limited partnership units, as determined by independent consultants retained by the Independent Board Committee. As at January 1, 2013, no Senior Executives have any further direct or indirect ownership of the St. Leon Wind Facility.

Office Facilities

APUC has leased its head office facilities since 2001 on a triple net basis from an entity partially owned by the Senior Executives. Base lease costs for the year ended December 31, 2014 were $315 (2013 - $310). In the fourth quarter of 2014, APUC moved all head office employees into new premises and terminated the related party lease for nominal consideration. There is no further related party matter in relation to an office lease.

Chartered Aircraft

As part of its normal business practice, APUC has utilized chartered aircraft when it is beneficial to do so and had previously entered into an agreement to charter aircraft in which the Senior Executives have a partial ownership. During the year ended December 31, 2013, APUC reimbursed direct costs in connection with the use of the aircraft of $472. As at December 31, 2013, the Independent Board Committee and the Parties agreed that all future utilization of chartered aircraft would be undertaken through a third-party charter operator at fair market value and under arrangements in which the Senior Executives have no interest. Final arrangements in this regard had not been completed as at December 31, 2014. During the year ended December 31, 2014, APUC reimbursed direct costs in connection with the use of the aircraft of $709.

Trafalgar

The Company owns debt on seven hydroelectric facilities owned by Trafalgar Power Inc. and an affiliate ("Trafalgar"). In 1997, Trafalgar went into default under its debt obligations and an affiliate of APMI moved to foreclose on the assets. Subsequently Trafalgar went into bankruptcy. APUC and the affiliate of APMI have been jointly involved in litigation and in bankruptcy proceedings with Trafalgar since 2004. APMI initially funded $2 million in legal fees prior to 2004.

In 2004, the Company reimbursed APMI $1 million of the total third-party legal fees (which to that point totalled $2 million), and APUC agreed to fund future legal fees, third-party costs and other liabilities. It was agreed that any net proceeds from the lawsuits would be shared proportionally to the quantum of net costs funded by each party.

(in thousands of Canadian dollars, except as noted and per share amounts)

18. Related party transactions (continued)

Other related party transactions

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

- For the year ended December 31, 2014, the Company sold electricity to Maine Public Service Company ("MPS"), a subsidiary of Emera, amounting to U.S. $5,780 (2013 - U.S. $6,042). In 2011, APUC provided a corporate guarantee to MPS in an amount of U.S. $3,000 and a letter of credit in an amount of U.S. $100, primarily in conjunction with a three year contract to provide standard offer service to commercial and industrial customers in Northern Maine. For the year ended December 31, 2014, the Company purchased natural gas amounting to U.S. $5,006 (2013 - U.S. $1,304) from Emera for its gas utility customers. Both the sale of electricity to Emera and the purchase of natural gas from Emera followed a public tender process, the results of which were approved by the regulator in the relevant jurisdiction.
- In 2011, APUC provided a corporate guarantee in an amount of U.S. $1,000 to a subsidiary of Emera providing lead market participant services for fuel capacity and forward reserve markets to ISO NE for the Windsor Locks facility. There has not been any transaction under this contract in the last three years.

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

Other

A spouse of one of the Senior Executives provided market research consulting services to certain subsidiaries of the Company. During the year ended December 31, 2014 APUC paid $192 (2013 - $45) in relation to these services.

19. Non-controlling interests

Net loss attributable to non-controlling interests consists of the following:

	2014	2013
Net earnings attributable to Class B partnership units of Wind Portfolio SponsorCo	**$ 3,484**	$ 9,556
Net loss attributable to Class A partnership units	**(27,199)**	(20,408)
Other net earnings attributable to non-controlling interests	**1,529**	39
Total net loss attributable to non-controlling interests	**$ (22,186)**	$ (10,813)

On March 31, 2014, the Company acquired the remaining Class B partnership units of Wind Portfolio SponsorCo from the non-controlling interest holder. As a result of the transaction, the Company now owns 100% of Wind Portfolio SponsorCo's Class B partnership units (note 3(g)).

The non-controlling Class A membership equity investors ("Class A partnership units") of Wind Portfolio SponsorCo and of the Bakersfield Solar Project, beginning December 31, 2014 are entitled to allocations of earnings, tax attributes and cash flows in accordance with contractual agreements. The share of earnings attributable to the non-controlling interest holders in these subsidiaries is calculated using the HLBV method of accounting as described in note 1(t).

(in thousands of Canadian dollars, except as noted and per share amounts)

20. Income taxes

The provision for income taxes in the consolidated statements of operations represents an effective tax rate different than the Canadian enacted statutory rate of 26.5% (2013 - 26.5%). The differences are as follows:

	2014	2013
Expected income tax expense at Canadian statutory rate	$ 19,199	$ 16,072
Increase (decrease) resulting from:		
Recognition of deferred credit	(5,763)	(6,676)
Effect of differences in tax rates on transactions in and within foreign jurisdictions and change in tax rates	(1,677)	(2,338)
Non-taxable corporate dividend	(2,618)	(2,896)
Non-controlling interests share of income	8,824	4,266
Production tax credit	(339)	(247)
Allowance for equity funds used during construction	(746)	(694)
State taxes	604	313
Other	(677)	1,355
Income tax expense	$ 16,807	$ 9,155

For the years ended December 31, 2014 and 2013, earnings from continuing operations before income taxes consists of the following:

	2014	2013
Canadian operations	$ 11,930	$ 19,687
U.S. operations	60,519	40,962
	$ 72,449	$ 60,649

Income tax expense (recovery) attributable to income (loss) consists of:

	Current	Deferred	Total
Year ended December 31, 2014			
Canada	$ 5,660	$ (3,538)	$ 2,122
United States	(1,986)	16,671	14,685
	$ 3,674	$ 13,133	$ 16,807
Year ended December 31, 2013			
Canada	$ 1,532	$ 881	$ 2,413
United States	994	5,748	6,742
	$ 2,526	$ 6,629	$ 9,155

(in thousands of Canadian dollars, except as noted and per share amounts)

20. Income taxes (continued)

The tax effect of temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases that give rise to significant portions of the deferred tax assets and deferred tax liabilities as of December 31, 2014 and 2013 are presented below:

	2014	2013
Deferred tax assets:		
Non-capital loss, investment tax credits, currently non-deductible interest expenses, and financing costs	$ **319,056**	$ 226,314
Pension and OPEB	**54,458**	31,433
Acquisition related costs	**5,168**	5,152
Environmental obligation	**28,555**	23,076
Production tax credit	**2,098**	1,633
Reserves not currently deductible	**2,315**	2,397
Other	**3,988**	2,780
Total deferred income tax assets	**415,638**	292,785
Less valuation allowance	**(15,534)**	(15,667)
Total deferred tax assets	**400,104**	277,118
Deferred tax liabilities:		
Property, plant and equipment	**(387,931)**	(267,344)
Intangible assets	**(2,752)**	(8,321)
Outside basis in partnership	**(15,194)**	(2,210)
Regulatory accounts	**(49,399)**	(24,745)
Financial derivatives	**(15,013)**	(7,675)
Total deferred tax liabilities	**(470,289)**	(310,295)
Net deferred tax liabilities	$ **(70,185)**	$ (33,177)

The valuation allowance for deferred tax assets as at December 31, 2014 was $(15,534) (2013 - $(15,667)). The valuation allowance primarily relates to operating losses that, in the judgment of management, are not more likely than not to be realized. In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities (including the impact of available carry back and carry forward periods), projected future taxable income, and tax-planning strategies in making this assessment.

Deferred income taxes are classified in the financial statements as:

	2014	2013
Current deferred income tax asset	$ **7,210**	$ 19,652
Non-current deferred income tax asset	**57,065**	86,632
Current deferred income tax liability	**(3,702)**	(2,308)
Non-current deferred income tax liability	**(130,758)**	(137,153)
	$ **(70,185)**	$ (33,177)

(in thousands of Canadian dollars, except as noted and per share amounts)

20. Income taxes (continued)

As of December 31, 2014, the Company had non-capital losses carry forwards available to reduce future year's taxable income, which expire as follows:

Year of expiry	Non-capital loss carryforwards	
2015	$	5,426
2016 and onwards		733,022
	$	738,448

On October 27, 2009, unitholders of Algonquin Power Income Fund exchanged their trust units on a one-for-one basis for common shares of APUC (the "Unit Exchange Transaction"). As a result of the Unit Exchange Transaction, APUC recorded certain additional tax attributes to the extent management believed they were more likely than not to be realized. The excess of the carrying amount of the tax attributes assumed over the consideration paid was recorded as a deferred credit of $55,647 on the date of the Unit Exchange Transaction (the "Transaction Date"). The deferred credit has been recognized into income as a deferred income tax recovery in relative proportion to the amount of the related tax attributes that have been utilized since the Transaction Date.

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

Should APUC receive a Notice of Reassessment covering the 2009, 2010, 2011, 2012 and 2013 taxation years, APUC will be required to make a deposit payment of 50% of the tax liability (including interest and any applicable penalties) claimed by the CRA in order to appeal the expected reassessment. Based on the tax amounts related to the 2009 to 2013 taxation years, that payment amount would be approximately $17,500. Additionally, assuming 2014 return will be similarly reassessed, a further payment of approximately $3,100 would also be required. APUC would also be required to make a deposit payment of 50% of the taxes the CRA claims are owed in any future tax year if the CRA were to issue a similar Notice of Reassessment for such years and APUC were to appeal it.

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

APUC remains confident in the appropriateness of its tax filing position and the expected tax consequences of the Unit Exchange Transaction and intends to vigorously defend such position. APUC strongly believes that the acquisition of control or the general anti-avoidance rules do not apply to the Unit Exchange Transaction and intends to file its future tax returns on a basis consistent with its previous tax returns. As a result, the probability of any potential final cash payment and impact on net earnings cannot be estimated at this time, but could range from $nil to $45,000.

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

(in thousands of Canadian dollars, except as noted and per share amounts)

21. Basic and diluted net earnings per share

Basic and diluted earnings per share have been calculated on the basis of net earnings attributable to the common shareholders of the Company and the weighted average number of common shares outstanding and subscription receipts issued (note 14 (a)(iii)) during the year. Diluted net earnings per share is computed using the weighted-average number of common shares, subscription receipts issued, additional shares issued subsequent to year-end under the dividend reinvestment plan, PSUs and DSUs outstanding during the period and, if dilutive, potential incremental common shares issuable upon the exercise of stock options. The dilutive effect of outstanding stock options is reflected in diluted earnings per share by application of the treasury stock method.

The reconciliation of the net earnings and the weighted average shares used in the computation of basic and diluted earnings per share are as follows:

	2014	2013
Net earnings attributable to shareholders of APUC	$ **75,701**	$ 20,296
Series A Preferred shares dividend	**5,400**	5,400
Series D Preferred shares dividend	**4,103**	—
Net earnings attributable to common shareholders of APUC	$ **66,198**	$ 14,896
Discontinued operations	**(2,127)**	(42,011)
Net earnings attributable to common shareholders of APUC from continuing operations - Basic and Diluted	$ **68,325**	$ 56,907
Weighted average number of shares		
Basic	**213,953,870**	204,350,689
Effect of dilutive securities	**2,387,722**	1,482,515
Diluted	**216,341,592**	205,833,204

The shares potentially issuable as a result of 1,786,401 stock options (2013 – 885,418) are excluded from this calculation as they are anti-dilutive.

22. Segmented information

During the fourth quarter, the Company aligned its management reporting under three business units - Generation, Transmission and Distribution. As a result, APUC has four reporting segments. Under Generation, the Company owns or has interests in hydroelectric, solar and wind power facilities which are aggregated as the renewable segment and operates co-generation, steam production and other thermal facilities which are aggregated as the thermal segment. The Distribution reporting segment now aggregates the electric, natural gas and water distribution utilities into a single reporting segment. Finally, the Transmission reporting segment, invests in rate regulated electric transmission and natural gas pipeline systems.

The operating segments were aggregated as generation (renewable, thermal), distribution and transmission based on their economic characteristics. The Transmission segment includes the new equity method investment in the Natural Gas Pipeline Development (note 8(b)) which is not yet significant and as a result is not presented separately in the tables below.

For purposes of evaluating divisional performance, the Company allocates the realized portion of any gains or losses on financial instruments to specific divisions. The unrealized portion of any gains or losses on derivative instruments not designated in a hedging relationship is not considered in management's evaluation of divisional performance and is therefore allocated and reported in the corporate segment. The results of operations and assets for these new segments are reflected in the tables below. The comparative information for 2013 has been reclassified to conform with the composition of the reporting segments presented in the current year.

(in thousands of Canadian dollars, except as noted and per share amounts)

22. Segmented information (continued)

	Year ended December 31, 2014					
	Generation			Distribution	Corporate	Total
	Renewable	Thermal	Total			
Revenue						
Regulated electricity distribution	$ —	$ —	$ —	$ 206,667	$ —	$ 206,667
Regulated gas distribution	—	—	—	446,025	—	446,025
Regulated water reclamation and distribution	—	—	—	66,419	—	66,419
Non-regulated energy sales	159,400	42,900	202,300	—	—	202,300
Other revenue	13,257	3,208	16,465	5,684	—	22,149
Total revenue	172,657	46,108	218,765	724,795	—	943,560
Operating expenses	46,077	9,405	55,482	180,442	60	235,984
Regulated electricity purchased	—	—	—	120,506	—	120,506
Regulated gas purchased	—	—	—	261,116	—	261,116
Non-regulated energy purchased	16,676	22,588	39,264	—	—	39,264
	109,904	14,115	124,019	162,731	(60)	286,690
Administrative expenses	(13,120)	(337)	(13,457)	(19,947)	(1,288)	(34,692)
Depreciation of property, plant and equipment	(48,479)	(5,980)	(54,459)	(52,387)	(2,128)	(108,974)
Amortization of intangible assets	(2,979)	(891)	(3,870)	(756)	—	(4,626)
Other amortization	81	—	81	(528)	—	(447)
Gain on foreign exchange	—	—	—	—	1,112	1,112
Interest expense	(32,117)	(1,751)	(33,868)	(27,139)	(1,411)	(62,418)
Interest, dividend income and other income	1,683	(496)	1,187	3,369	3,202	7,758
Gain on sale of asset	110	326	436	—		436
Acquisition-related costs	—	—	—	—	(2,552)	(2,552)
Write-down of long-lived assets	—	(698)	(698)	(300)	(7,465)	(8,463)
Gain (loss) on derivative financial instruments	214	—	214	—	(1,589)	(1,375)
Earnings from continuing operations before income taxes	15,297	4,288	19,585	65,043	(12,179)	72,449
Loss from discontinued operations before income taxes	(3,189)	(216)	(3,405)	—	—	(3,405)
Earnings (loss) before income taxes	$ 12,108	$ 4,072	$ 16,180	$ 65,043	$ (12,179)	$ 69,044
Property, plant and equipment	$1,602,465	$ 85,000	$1,687,465	$1,531,166	$ 59,791	$3,278,422
Equity-method investees	2,267	1,253	3,520	1,563	1,652	6,735
Total assets	1,795,757	100,603	1,896,360	2,106,638	111,417	4,114,415
Capital expenditures	197,051	4,012	201,063	176,849	54,461	432,373
Acquisition of operating entities	—	—	—	8,757	—	8,757

(in thousands of Canadian dollars, except as noted and per share amounts)

22. Segmented information (continued)

	Year ended December 31, 2013					
	Generation			Distribution	Corporate	Total
	Renewable Energy	Thermal Energy	Total			
Revenue						
Regulated electricity distribution	$ —	$ —	$ —	$ 166,156	$ —	$ 166,156
Regulated gas distribution	—	—	—	260,424	—	260,424
Regulated water reclamation and distribution	—	—	—	57,350	—	57,350
Non-regulated energy sales	145,661	34,530	180,191	—	—	180,191
Other revenue	7,058	2,442	9,500	1,270	400	11,170
Total revenue	152,719	36,972	189,691	485,200	400	675,291
Operating expenses	40,282	8,514	48,796	131,550	—	180,346
Regulated electricity purchased	—	—	—	97,376	—	97,376
Regulated gas purchased	—	—	—	148,784	—	148,784
Non-regulated energy purchased	8,684	17,151	25,835	—	—	25,835
	103,753	11,307	115,060	107,490	400	222,950
Administrative expenses	(13,094)	(223)	(13,317)	(7,477)	(2,724)	(23,518)
Depreciation of property, plant and equipment	(45,122)	(5,439)	(50,561)	(41,417)	—	(91,978)
Amortization of intangible assets	(2,652)	(856)	(3,508)	(692)	—	(4,200)
Other amortization	81	—	81	78	—	159
Gain on foreign exchange	—	—	—	—	567	567
Interest expense	(27,472)	(1,046)	(28,518)	(23,734)	(1,174)	(53,426)
Interest, dividend income and other income	1,867	193	2,060	3,228	2,497	7,785
Loss on sale of asset	(750)	—	(750)	—	—	(750)
Acquisition-related costs	—	—	—	—	(2,140)	(2,140)
Gain (loss) on derivative financial instruments	(767)	—	(767)	—	5,967	5,200
Earnings from continuing operations before income taxes	15,844	3,936	19,780	37,476	3,393	60,649
Loss from discontinued operations before income taxes	1,128	(61,630)	(60,502)	—	—	(60,502)
Earnings (loss) before income taxes	$ 16,972	$ (57,694)	$ (40,722)	$ 37,476	$ 3,393	$ 147
Property, plant and equipment	$1,364,843	$ 79,828	$1,444,671	$1,264,033	$ —	$2,708,704
Equity-method investees	—	1,718	1,718	325	8,623	10,666
Total assets	1,492,144	116,922	1,609,066	1,673,631	193,784	3,476,481
Capital expenditures	46,885	2,631	49,516	108,861	—	158,377
Acquisition of operating entities	2,083	—	2,083	236,931	—	239,014

(in thousands of Canadian dollars, except as noted and per share amounts)

22. Segmented information (continued)

Operational segments (continued)

The majority of non-regulated energy sales are earned from contracts with large public utilities. The following utilities contributed more than 10% of these total revenues in either 2014 or 2013: Hydro Québec 11% (2013 - 14%) and Manitoba Hydro 13% (2013 - 14%). The Company has mitigated its credit risk to the extent possible by selling energy to large utilities in various North American locations.

APUC operates in the independent power and utility industries in both Canada and the United States. Information on operations by geographic area is as follows:

	2014	2013
Revenue		
Canada	**$ 92,267**	$ 65,380
United States	**851,293**	609,911
	$ 943,560	$ 675,291
Property, plant and equipment		
Canada	**$ 590,580**	$ 433,153
United States	**2,687,842**	2,275,551
	$ 3,278,422	$ 2,708,704
Intangible assets		
Canada	**$ 25,601**	$ 26,802
United States	**28,410**	27,614
	$ 54,011	$ 54,416

Revenues are attributed to the two countries based on the location of the underlying generating and utility facilities.

23. Commitments and contingencies

(a) Contingencies

APUC and its subsidiaries are involved in various claims and litigation arising out of the ordinary course and conduct of its business. Although such matters cannot be predicted with certainty, management does not consider APUC's exposure to such litigation to be material to these financial statements, with the exception of those matters described below. Accruals for any contingencies related to these items are recorded in the financial statements at the time it is concluded that its occurrence is probable and the related liability is estimable.

(i) On October 21, 2011, the Quebec Court of Appeal ordered a subsidiary of APUC to pay approximately $5,400 (including interest) to the Government of Quebec relating to water lease payments that the APUC subsidiary has been paying to the St. Lawrence Seaway Management Corporation ("Seaway Management") under its water lease with Seaway Management in prior years.

The water lease with Seaway Management contains an indemnification clause which management believes mitigates this claim and management intends to vigorously defend its position. As a result, the probability of loss, if any, and its quantification cannot be estimated at this time but could range from $nil to $6,400. In 2012, the Company paid an amount of $1,884 to the government of Quebec in relation to the early years covered by the claim in order to mitigate the impact of accruing interests on any amount ultimately determined to be payable or recoverable.

(in thousands of Canadian dollars, except as noted and per share amounts)

23. Commitments and contingencies (continued)

(a) Contingencies (continued)

(ii) The normal ongoing operations and historic activities of the Company are subject to various federal, state and local environmental laws and regulations and are regulated by agencies such as the United States Environmental Protection Agency, the New Hampshire Department of Environmental Services and the Massachusetts Department of Environmental Protection.

Like most other industrial companies, the gas and electric distribution utilities generate some hazardous wastes. Under federal and state 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 regulated utilities, these costs are often allowed in rate case proceedings to be recovered from rate payers over a specified period.

Prior to their acquisition by the Company, EnergyNorth Gas, Granite State Electric and New England Gas Systems were named as potentially responsible parties for remediation of several sites at which hazardous waste is alleged to have been disposed as a result of historic operations of Manufactured Gas Plants ("MGP") and related facilities. The Company is currently investigating and remediating, as necessary, those MGP and related sites in accordance with plans submitted to the agency with authority for each of the respective sites. The Company believes that obligations imposed on it because of those sites will not have a material impact on its results of operations.

The Company estimates the remaining undiscounted, unescalated cost of these MGP-related environmental cleanup activities will be $72,594 which at discount rates ranging from 2.1% to 3.4% represents the recorded accrual of $72,305 as of December 31, 2014 (December 31, 2013 - $69,555).

By rate orders, the Regulator provided for the recovery of actual expenditures for site investigation and remediation over a period of 7 years and accordingly, as of December 31, 2014, the Company has reflected a regulatory asset of $102,735 (December 31, 2013 - $85,029) for the MGP and related sites (note 7(a)).

Estimated cash flows for site investigation and remediation costs in the next five years and thereafter are as follows:

2015	$ 19,643
2016	22,229
2017	14,394
2018	5,443
2019	629
Thereafter to 2046	10,256
	$ 72,594

(b) Commitments

In addition to the commitments related to the proposed acquisitions and development projects disclosed in notes 3 and 8, the following significant commitments exist as of December 31, 2014.

As a result of the dam safety legislation passed in Quebec (Bill C-93), APUC has completed technical assessments on its hydroelectric facility dams owned or leased within the Province of Quebec. The assessments have identified a number of remedial measures required to meet the new safety standards. APUC currently estimates further capital expenditures of approximately $7,900 over a period of five years related to compliance with the legislation.

(in thousands of Canadian dollars, except as noted and per share amounts)

23. Commitments and contingencies (continued)

(b) Commitments (continued)

APUC has outstanding purchase commitments for power purchases, gas delivery, service and supply, service agreements, capital project commitments and operating leases. Detailed below are estimates of future commitments under these arrangements:

	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter	Total
Purchased power	$118,158	$ —	$ —	$ —	$ —	$ —	$ 118,158
Gas delivery, service and supply agreements	52,848	37,714	30,318	27,718	27,625	88,234	264,457
Service agreements	28,572	32,147	32,537	31,556	31,382	481,061	637,255
Capital projects	21,972	—	—	—	—	—	21,972
Operating leases	5,647	4,951	4,604	4,274	4,190	97,421	121,087
Total	$227,197	$ 74,812	$67,459	$63,548	$63,197	$666,716	$1,162,929

Calpeco Electric System has entered into a five-year all-purpose power purchase agreement with NV Energy to provide its full electric requirements at NV Energy's "system average cost" rates. The PPA has an effective starting date of January 1, 2011 with a five-year renewal option. The commitment amounts included in the table above are based on market prices as of December 31, 2014. However, the effects of purchased power unit cost adjustments are mitigated through a purchased power rate-adjustment mechanism. Granite State Electric System has several types of contracts for the purchase of electric power. Substantially all of these contracts require power to be delivered before the Company is obligated to make payment.

24. Non-cash operating items

The changes in non-cash operating items from discontinued operations consist of the following:

	2014	2013
Accounts receivable	$ **2,572**	$ (213)
Prepaid expenses	**36**	(11)
Accrued liabilities	**(1,346)**	260
	$ **1,262**	$ 36

The changes in non-cash operating items consist of the following:

	2014	2013
Accounts receivable	$ **(23,640)**	$ (49,888)
Related party balances	—	(996)
Natural gas in storage	**(5,942)**	(6,330)
Supplies and consumable inventory	**(3,861)**	(525)
Income taxes receivable	**(189)**	177
Prepaid expenses	**827**	(485)
Accounts payable	**54,299**	(29,292)
Accrued liabilities	**32,520**	37,023
Current income tax liability	**(1,527)**	1,399
Net regulatory assets and liabilities	**(54,277)**	1,098
	$ **(1,790)**	$ (47,819)

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments

(a) Fair value of financial instruments

2014	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	$ 39,510	$ 41,339	$ —	$ 41,339	$ —
Derivative financial instruments:					
Energy contracts designated as a cash flow hedge	41,966	41,966	—	—	41,966
Energy contracts not designated as a cash flow hedge	504	504	—	—	504
Total derivative financial instruments	42,470	42,470	—	—	42,470
Total financial assets	$ 81,980	$ 83,809	$ —	$ 41,339	$ 42,470
Long-term liabilities	$ 1,280,023	$ 1,363,934	$ 520,142	$ 843,792	$ —
Preferred shares, Series C	18,693	18,209	—	18,209	—
Derivative financial instruments:					
Cross-currency swap designated as a net investment hedge	36,276	36,276	—	36,276	—
Interest rate swap designated as a hedge	4,684	4,684	—	4,684	—
Interest rate swaps not designated as a hedge	1,383	1,383	—	1,383	—
Commodity contracts for regulated operations	2,928	2,928	—	2,928	—
Total derivative financial instruments	45,271	45,271	—	45,271	—
Total financial liabilities	$ 1,343,987	$ 1,427,414	$ 520,142	$ 907,272	$ —

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments (continued)

(a) Fair value of financial instruments (continued)

2013	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	$ 22,678	$ 26,321	$ —	$ 26,321	$ —
Derivative financial instruments:					
Energy contracts designated as a cash flow hedge	31,971	31,971	—	—	31,971
Energy contracts not designated as a cash flow hedge	3,737	3,737	—	—	3,737
Cross-currency swap designated as a net investment hedge	109	109	—	109	—
Commodity contracts for regulatory operations	482	482	—	482	—
Total derivative financial instruments	36,299	36,299	—	591	35,708
Total financial assets	$ 58,977	$ 62,620	$ —	$ 26,912	$ 35,708
Long-term liabilities	$1,255,588	$1,261,340	$ 296,986	$ 964,354	$ —
Preferred shares, Series C	18,805	18,293		18,293	—
Derivative financial instruments:					
Energy contracts designated as a cash flow hedge	4,781	4,781	—	—	4,781
Cross-currency swap designated as a net investment hedge	7,947	7,947	—	7,947	—
Interest rate swaps not designated as a hedge	3,180	3,180	—	3,180	—
Commodity contracts for regulated operations	313	313	—	313	—
Total derivative financial instruments	16,221	16,221	—	11,440	4,781
Total financial liabilities	$1,290,614	$1,295,854	$ 296,986	$ 994,087	$ 4,781

25. Financial instruments (continued)

(a) Fair value of financial instruments (continued)

The Company has determined that the carrying value of its short-term financial assets and liabilities approximates fair value as of December 31, 2014 and 2013 due to the short-term maturity of these instruments.

Notes receivable fair values (level 2) have been determined using a discounted cash flow method, using estimated current market rates for similar instruments adjusted for estimated credit risk as determined by management.

The Company's level 2 fair value of long-term liabilities at fixed interest rates and Series C preferred shares has been determined using a discounted cash flow method and current interest rates.

The Company's level 2 fair value derivative instruments primarily consist of swaps, options and forward physical deals where market data for pricing inputs are observable. Level 2 pricing inputs are obtained from various market indices and utilize discounting based on quoted interest rate curves which are observable in the marketplace.

The Red Lily conversion option is measured at fair value on a recurring basis using unobservable inputs (level 3). The fair value is based on an income approach using an option pricing model that includes various inputs such as energy yield function from wind, estimated cash flows and a discount rate of 9.0%. The Company used a discount rate believed to be most relevant given the business strategy. There was no change in fair value of $nil during the years ended December 31, 2014 or 2013.

The Company's level 3 instruments consist of energy contracts for electricity sales. The significant unobservable inputs used in the fair value measurement of energy contracts are the internally developed forward market prices ranging from $16.62 to $113.93 with a weighted average of $39.72 as of December 31, 2014. The processes and methods of measurement are developed using the market knowledge of the trading operations within the Company and are derived from observable energy curves adjusted to reflect the illiquid market of the hedges and, in some cases, the variability in deliverable energy. Significant increases (decreases) in any of these inputs in isolation would result in a significantly lower (higher) fair value measurement. The change in the fair value of the energy contracts are detailed in notes 25(b)(ii) and 25(b)(iv).

Fair value estimates are made at a specific point in time, using available information about the financial instrument. These estimates are subjective in nature and often cannot be determined with precision.

The Company's accounting policy is to recognize transfers between levels of the fair value hierarchy on the date of the event or change in circumstances that caused the transfer. There was no transfer into or out of level 1, level 2 or level 3 during the years ended December 31, 2014 or 2013.

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments (continued)

(b) Derivative instruments

Derivative instruments are recognized on the consolidated balance sheets as either assets or liabilities and measured at fair value each reporting period.

(i) Commodity derivatives – regulated accounting

The Company uses derivative financial instruments to reduce the cash flow variability associated with the purchase price for a portion of future natural gas purchases associated with its regulated gas service territories. The Company's strategy is to minimize fluctuations in gas sales prices to regulated customers.

The following are commodity volumes, in dekatherms ("dths") associated with the above derivative contracts:

	2014
Financial contracts: Gas swaps	1,774,018
Gas options	907,758
	2,681,776

The accounting for these derivative instruments is subject to guidance for rate-regulated enterprises. Therefore, the fair value of these derivatives is recorded as current or long-term assets and liabilities, with offsetting positions recorded as regulatory assets and regulatory liabilities in the consolidated balance sheets. Gains or losses on the settlement of these contracts are included in the calculation of deferred gas costs (note 7(d)). As a result, the changes in fair value of these natural gas derivative contracts and their offsetting adjustment to regulatory assets and liabilities had no earnings impact. The following table presents the impact of the change in the fair value of the Company's natural gas derivative contracts had on the consolidated balance sheets:

		2014		2013
Regulatory assets:				
Gas swap contracts	U.S. $	**2,178**	U.S. $	86
Gas option contracts	U.S. $	**346**	U.S. $	208
Regulatory liabilities:				
Gas swap contracts	U.S. $	—	U.S. $	416
Gas option contracts	U.S. $	—	U.S. $	37

(ii) Cash flow hedges

The Company reduces the price risk on the expected future sale of power generation at Sandy Ridge, Senate and Minonk Wind Facilities and at one of its hydro facilities no longer subject to a power purchase agreement by entering into the following long-term energy derivative contracts.

Notional quantity (MW-hrs)	Expiry	Receive average prices (per MW-hr)		Pay floating price (per MW-hr)
98,167	December 2016	$	67.91	AESO
915,428	December 2022	U.S. $	42.81	PJM Western HUB
3,907,711	December 2022	U.S. $	30.25	NI HUB
4,330,303	December 2027	U.S. $	36.46	ERCOT North HUB

On November 14, 2014, the Company entered into a 10-year forward-starting interest rate swap beginning on July 25, 2018 in order to reduce the interest rate risk related to the probable issuance on that date of a 10-year $135,000 bond. The change in fair value resulted in a loss of $4,684 for the year ended December 31, 2014, which is recorded in OCI.

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments (continued)

(b) Derivative instruments (continued)

(ii) Cash flow hedges (continued)

The following table summarizes changes in OCI attributable to derivative financial instruments designated as a cash flow hedge:

		2014		2013
Effective portion of cash flow hedge, loss	$	**1,043**	$	18,940
Amortization on cash flow hedge		**(32)**		(30)
Loss (gain) reclassified from AOCI into non-regulated energy sales		**5,423**		(1,602)
	$	**6,434**	$	17,308
Less non-controlling interest		**5,982**		(9,064)
Change in OCI attributable to shareholders of APUC	$	**12,416**	$	8,244

The Company expects $10,132 of unrealized gains currently in AOCI to be reclassified into non-regulated energy sales within the next twelve months, as the underlying hedged transactions settle.

(iii) Foreign exchange hedge of net investment in foreign operation

The Company periodically uses a combination of foreign exchange forward contracts and spot purchases to manage its foreign exchange exposure on cash flows generated from the U.S. operations. APUC only enters into foreign exchange forward contracts with major Canadian financial institutions having a credit rating of A or better, thus reducing credit risk on these forward contracts.

Concurrent with its $150,000 and $200,000 debenture offerings in December 2012 and January 2014, respectively, the Company entered into cross currency swaps, coterminous with the debentures, to effectively convert the Canadian dollar denominated offering into U.S. dollars. The Company designated the entire notional amount of the cross currency fixed-for-fixed interest rate swap and related short-term U.S. dollar payables created by the monthly accruals of the swap settlement as a hedge of the foreign currency exposure of its net investment in the Generation Group's U.S. operations. The gain or loss related to the fair value changes of the swap and the related foreign currency gains and losses on the U.S. dollar accruals that are designated as, and are effective as, a hedge of the net investment in a foreign operation are reported in the same manner as the translation adjustment (in OCI) related to the net investment. A loss of $28,537 (2013 - loss of $5,771) was recorded in OCI in 2014.

(iv) Other derivatives

The Company provides energy requirements to various customers under contracts at fixed rates. While the production from the Tinker Assets are expected to provide a portion of the energy required to service these customers, APUC anticipates having to purchase a portion of its energy requirements at the ISO NE spot rates to supplement self-generated energy.

This risk is mitigated though the use of short-term financial forward energy purchase contracts which are classified as derivative instruments. The electricity derivative contracts are net settled fixed-for-floating swaps whereby APUC pays a fixed price and receives the floating or indexed price on a notional quantity of energy over the remainder of the contract term at an average rate, as per the following table. These contracts are not accounted for as hedges and changes in fair value are recorded in earnings as they occur.

Notional quantity (MW-hrs)	Expiry	Receive average prices (per MW-hr)			Net Asset
18,283	March 2015	U.S. $	57.53	$	417

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments (continued)

(b) Derivative instruments (continued)

(iv) Other derivatives (continued)

The Company is party to an interest rate swap whereby, the Company pays a fixed interest rate of 4.47% on a notional amount of $60,513 and receives floating interest at 90 day CDOR, up to the expiry of the swap in September 2015. As of December 31, 2014, the estimated fair value of the interest rate swap was a liability of $1,383 (2013 – liability of $3,180). This interest rate swap is not being accounted for as a hedge and consequently, changes in fair value are recorded in earnings as they occur.

For derivatives that are not designated as cash flow hedges and for the ineffective portion of gains and losses on derivatives that are accounted for as hedges, the changes in the fair value are immediately recognized in earnings.

The effects on the consolidated statements of operations of derivative financial instruments not designated as hedges consist of the following:

	2014	2013
Change in unrealized loss (gain) on derivative financial instruments:		
Interest rate swaps	**$ (1,797)**	$ (1,598)
Energy derivative contracts	**3,386**	(3,809)
Total change in unrealized loss (gain) on derivative financial instruments	**$ 1,589**	$ (5,407)
Realized loss (gain) on derivative financial instruments:		
Interest rate swaps	**1,962**	2,024
Energy derivative contracts	**(3,627)**	(466)
Total realized loss (gain) on derivative financial instruments	**$ (1,665)**	$ 1,558
Gain on derivative financial instruments not accounted for as hedges	**(76)**	(3,849)
Ineffective portion of derivative financial instruments accounted for as hedges	**1,451**	(1,351)
Loss (gain) on derivative financial instruments	**$ 1,375**	$ (5,200)

(c) Risk management

In the normal course of business, the Company is exposed to financial risks that potentially impact its operating results. The Company employs risk management strategies with a view of mitigating these risks to the extent possible on a cost effective basis. Derivative financial instruments are used to manage certain exposures to fluctuations in exchange rates, interest rates and commodity prices. The Company does not enter into derivative financial agreements for speculative purposes.

This note provides disclosures relating to the nature and extent of the Company's exposure to risks arising from financial instruments, including credit risk, liquidity risk, foreign currency risk and interest rate risk, and how the Company manages those risks.

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments (continued)

(c) Risk management (continued)

Credit risk

Credit risk is the risk of an unexpected loss if a customer or counterparty to a financial instrument fails to meet its contractual obligations. The Company's financial instruments that are exposed to concentrations of credit risk are primarily cash and cash equivalents, accounts receivable, notes receivable and derivative instruments. The Company limits its exposure to credit risk with respect to cash equivalents by ensuring available cash is deposited with its senior lenders in Canada all of which have a credit rating of A or better. The Company does not consider the risk associated with accounts receivable to be significant as over 80% of revenue from power generation is earned from large utility customers having a credit rating of BBB or better, and revenue is generally invoiced and collected within 45 days.

The remaining revenue is primarily earned by the Distribution Group which consists of water and wastewater utilities, electric utilities and gas utilities in the United States. In this regard, the credit risk related to Distribution Group accounts receivable balances of U.S. $119,866 is spread over thousands of customers. The Company has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers. In addition, the state regulators of the Distribution Group allow for a reasonable bad debt expense to be incorporated in the rates and therefore recovered from rate payers.

As of December 31, 2014, the Company's maximum exposure to credit risk for these financial instruments was as follows:

	December 31, 2014	
	Canadian $	**US $**
Cash and cash equivalents and restricted cash	$ 5,823	$ 19,095
Accounts receivable	20,320	151,265
Allowance for doubtful accounts	—	(6,232)
Notes receivable	21,901	15,179
	$ 48,044	$ 179,307

In addition, the Company continuously monitors the creditworthiness of the counterparties to its foreign exchange, interest rate, and energy derivative contracts prior to settlement, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. The counterparties consist primarily of financial institutions. This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

As of December 31, 2014, an amount receivable under the derivatives for Sandy Ridge, Senate and Minonk Wind Facilities of $156 (2013 - $7,344) was held as collateral by the counterparty.

(in thousands of Canadian dollars, except as noted and per share amounts)

25. Financial instruments (continued)

(c) Risk management (continued)

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company's approach to managing liquidity risk is to ensure, to the extent possible, that it will always have sufficient liquidity to meet liabilities when due. As of December 31, 2014, in addition to cash on hand of $9,273 the Company had $485,927 available to be drawn on its senior debt facilities. Each of the Company's revolving credit facilities contain covenants which may limit amounts available to be drawn.

The Company's liabilities mature as follows:

	Due less than 1 year	Due 2 to 3 years	Due 4 to 5 years	Due after 5 years	Total
Long-term debt obligations	$ 9,130	$ 90,955	$ 218,795	$ 961,143	$ 1,280,023
Advances in aid of construction	1,149	—	—	79,955	81,104
Interest on long-term debt	64,232	125,268	102,070	146,689	438,259
Purchase obligations	267,914				267,914
Environmental obligation	19,643	36,623	6,072	10,256	72,594
Derivative financial instruments:					
Cross-currency swap	1,463	2,975	2,433	29,405	36,276
Interest rate forwards	—	—	4,684	—	4,684
Interest rate swaps	1,383	—	—	—	1,383
Energy derivative and commodity contracts	2,337	591	—	—	2,928
Other obligations	9,873	860	25	29,659	40,417
Total obligations	$ 377,124	$ 257,272	$ 334,079	$1,257,107	$2,225,582

Foreign currency risk

The Company is exposed to currency fluctuations from its U.S. based operations. APUC manages this risk primarily through the use of natural hedges by using U.S. long-term debt to finance its U.S. operations.

The Company designates the amounts drawn on the Generation Group's revolving credit facility denominated in U.S. dollars as a hedge of the foreign currency exposure of its net investment in the Generation Group's U.S. operations. The foreign currency transaction gain or loss on the outstanding U.S. dollar denominated balance of the facility that is designated as a hedge of the net investment in its foreign operations is reported in the same manner as a translation adjustment (in OCI) related to the net investment, to the extent it is effective as a hedge. A foreign currency loss of $2,727 for the year-ended December 31, 2014 (2013 - $1,607) was recorded in OCI.

Interest rate risk

The Company is exposed to interest rate fluctuations related to certain of its floating rate debt obligations, including certain project specific debt and its revolving credit facilities, its interest rate swaps as well as interest earned on its cash on hand. The Company does not currently hedge that risk.

26. Comparative figures

Certain of the comparative figures have been reclassified to conform to the financial statement presentation adopted in the current year.

NOTES

NOTES

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DIRECTORS

Kenneth Moore, Chairman – Managing Partner, NewPoint Capital Partners Inc.
Christopher Ball – Executive Vice-President, Corpfinance International Ltd.
Christopher Huskilson – President & Chief Executive Officer, Emera Inc.
Chris Jarratt – Vice-Chair, Algonquin Power & Utilities Corp.
Ian Robertson – Chief Executive Officer, Algonquin Power & Utilities Corp.
George Steeves – Principal, True North Energy
Masheed Saidi – Former Executive VP and Chief Operating Officer, US Transmission, National Grid USA
Dilek Samil - Former Executive VP and Chief Operating Officer, NV Energy

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