LAW OFFICES OF

ANDERSON & BYRD

A Limited Liability Partnership

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(1920-1994)

RICHARD C. BYRD
(1920-2008)

February 27, 2017

via e-filing EXPRESS

Ms. Amy L. Green, Secretary
Kansas Corporation Commission
1500 S. W. Arrowhead Road
Topeka, Kansas 66604-4027

Re: Docket No. 17-EPDE-393-CPL
Press Release and Prospectus Related to the Equity Financing

Dear Ms. Green:

Attached for filing with the Kansas Corporation Commission ("Commission") in the referenced docket are the following documents:

1. Algonquin Power & Utilities Corp., Convertible Debenture Prospectus

2. Algonquin Power & Utilities Corp., Convertible Debentures Press Release

These documents, which were previously filed in Docket No. 16-EPDE-410-ACQ ("410 Docket"), are being filed with the Commission in compliance with paragraph 64 contained in the Unanimous Settlement Agreement dated October 6, 2016, which was approved by the Commission in the 410 Docket by Order issued December 22, 2016.

Sincerely,

Jas G. Flaherty

James G. Flaherty
jflaherty@andersonbyrd.com

JGF:rr
Enclosure
cc: Thomas J. Connors
David W. Nickel
Della Smith
Shonda Smith
Jason K. Fisher
Dustin L. Kirk
Amber Smith

Algonquin Power & Utilities Corp. Issues 98,022,082 Common Shares Upon Conversion of Outstanding Convertible Debentures

Company Release - 02/03/2017 09:53

NOT FOR DISSEMINATION OR DISTRIBUTION IN THE UNITED STATES AND NOT FOR DISTRIBUTION TO UNITED STATES NEWSWIRE SERVICES OR TO U.S. PERSONS

OAKVILLE, ON, Feb. 3, 2017 /CNW/ - Algonquin Power & Utilities Corp. ("APUC") (TSX: AQN, NYSE: AQN) announced today the results of the final instalment payment in respect of its 5.00% convertible unsecured subordinated debentures ("Debentures") represented by instalment receipts ("Instalment Receipts"). Holders of $1,039,034,075 principal amount of Debentures have elected to convert their Debentures into APUC common shares ("Common Shares"). As a result, APUC has issued 98,022,082 Common Shares to former holders of Debentures. It is expected that $110,965,925 principal amount of Debentures will remain outstanding after giving effect to such conversions.

Holders of Debentures have the right, at any time prior to redemption or maturity, to convert their Debentures into Common Shares at a price of $10.60 per Common Share. On February 2, 2017, the closing price of the Common Shares on the Toronto Stock Exchange (the "TSX") was $11.58. Holders of Debentures are encouraged to exercise their conversion right before the next Common Share dividend record date to ensure that they receive future dividends paid by APUC. Conversion elections must be made by holders of Debentures through their broker, investment advisor or other intermediary.

Holders of Debentures are reminded that as of today the interest payable on the Debentures has fallen to an annual rate of 0%. As a result, no further interest will accrue or be paid on the Debentures. The Debentures are not and will not be listed on the TSX and may in the future be redeemed by APUC for 100% of their principal amount.

The Instalment Receipts, which until yesterday represented the interest of holders in the underlying Debentures, have now been cancelled and delisted from the TSX.

About Algonquin Power & Utilities Corp.

APUC is a North American diversified generation, transmission and distribution utility with $10 billion of total assets. Liberty Utilities provides rate regulated natural gas, water and electricity generation, transmission and distribution utility services to over 782,000 customers in the United States. APUC is committed to being a North American leader in the generation of clean energy through its portfolio of long term contracted wind, solar and hydroelectric generating facilities representing more than 1,150 MW of installed capacity. APUC delivers continuing growth through an expanding pipeline of renewable energy development projects, organic growth within its rate regulated generation, distribution and transmission businesses, and the pursuit of accretive acquisitions. Common shares and preferred shares are traded on the Toronto Stock Exchange under the symbols AQN, AQN.PR.A, and AQN.PR.D. APUC's common shares are also listed on the New York Stock Exchange under the symbol AQN. Visit APUC at www.AlgonquinPowerandUtilities.com and follow us on Twitter @AQN_Utilities.

Caution Regarding Forward-Looking Information

Certain matters discussed in this press release are "forward-looking statements" within the meaning of applicable securities laws. Statements that are not historical facts, including statements about beliefs, expectations, estimates, projections, goals, forecasts, assumptions, risks and uncertainties, are forward-looking statements. Forward-looking statements are often characterized by the use of words such as "believes," "estimates," "expects," "projects," "may," "intends," "plans," "anticipates," "pro forma," "predicts," "seeks," "could," "would," "will," "can," "continue" or "potential" and the negative of these terms or other comparable or similar terminology or expressions. The forward-looking statements in this press release include, without limitation, statements relating to the conversion of the Debentures. These statements reflect APUC management's current beliefs and are based on information currently available to APUC. Certain factors or assumptions have been applied in drawing the conclusions contained in the forward-looking statements (some of which may prove to be incorrect). APUC cautions readers that a number of factors could cause actual results, performance or achievement to differ materially from the results discussed or implied in the forward-looking statements.

Additional detailed information about these assumptions, risks and uncertainties is included in APUC's securities regulatory filings, including under the heading "Enterprise Risk Management" in APUC's annual Management's Discussion and Analysis and in its Annual Information Form, which can be found on SEDAR at www.sedar.com. Except as required by law, APUC disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

SOURCE Algonquin Power & Utilities Corp.

A copy of this preliminary short form prospectus has been filed with the securities regulatory authorities in each province of Canada but has not yet become final for the purpose of the sale of securities. Information contained in this preliminary short form prospectus may not be complete and may have to be amended. The securities may not be sold until a receipt for the short form prospectus is obtained from the securities regulatory authorities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions or similar authorities in Canada. *Copies of the documents incorporated herein by reference may be obtained on request without charge from the Corporate Secretary of the Corporation (as defined in this Prospectus) at 354 Davis Road, Oakville, Ontario, L6J 2X1, telephone (905) 465-4500, and are also available electronically at www.sedar.com.*

This Prospectus constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. ***These securities may not be offered or sold in the United States.*** *The securities being offered under this Prospectus have not been and will not be registered under the 1933 Act (as defined in this Prospectus) or any state securities laws, and may not be offered or sold within the United States (as defined in Regulation S under the 1933 Act). See "Plan of Distribution".*

Secondary Offering **February 15, 2016**

PRELIMINARY SHORT FORM PROSPECTUS

ALGONQUIN POWER & UTILITIES CORP.

$1,000,000,000
5.00% Convertible Unsecured Subordinated Debentures
represented by Instalment Receipts

The 5.00% convertible unsecured subordinated debentures (the "**Debentures**") of Algonquin Power & Utilities Corp. ("**Algonquin**", or, the "**Corporation**") offered hereby (the "**Offering**") will be sold by Liberty Utilities (Canada) Corp. (the "**Selling Debentureholder**"), a direct wholly-owned subsidiary of Algonquin, on an instalment basis at a price of $1,000 per Debenture. See "Details of the Offering – The Selling Debentureholder". Prior to full payment, beneficial ownership of the Debentures will be represented by instalment receipts (the "**Instalment Receipts**"). The first instalment of $333 is payable on the closing of the Offering. The final instalment of $667 is payable following notification to holders of Instalment Receipts (the "**Final Instalment Notice**") that: (i) the Corporation has received all regulatory and governmental approvals required to finalize the acquisition (the "**Acquisition**") by Liberty Utilities (Central) Co. ("**AcquisitionCo**") (a wholly-owned indirect subsidiary of the Corporation) of The Empire District Electric Company ("**Empire**"), an investor-owned, regulated utility company whose common stock is listed on the New York Stock Exchange ("**NYSE**"); and (ii) AcquisitionCo and Empire have fulfilled or waived all other outstanding conditions precedent to closing the Acquisition, other than those which by their nature cannot be satisfied until the closing of the Acquisition (collectively, the "**Approval Conditions**"), in each case as set out in the agreement and plan of merger dated February 9, 2016 among AcquisitionCo, Liberty Sub Corp. ("**Merger Sub**"), a direct wholly-owned subsidiary of AcquisitionCo, and Empire (the "**Acquisition Agreement**"). See "The Acquisition" and "The Acquisition Agreement". The Final Instalment Notice will set a date for payment of the final instalment (the "**Final Instalment Date**"), which shall not be less than 15 days nor more than 90 days following the date of such notice. **If a holder of an Instalment Receipt does not pay the final instalment on or before the Final Instalment Date, the Debentures represented by such Instalment Receipt may, at the option of the Selling Debentureholder, upon compliance with applicable law and the terms of the Instalment Receipt Agreement (as defined under** "**Details of the Offering – Instalment Receipts**"**), be forfeited to the Selling Debentureholder in full satisfaction of the holder's obligations or such Debentures may be sold and the holder will remain liable for any deficiency in the proceeds of such sale**. See "Details of the Offering".

The holders of Debentures will be entitled to interest at an annual rate of 5.00% per $1,000 principal amount of Debentures, payable quarterly in arrears in equal instalments on the 15th day of March, June, September and December of each year (or the next business day if the 15th falls on a weekend or holiday) to and including the Final

Instalment Date. The first interest payment will be made on June 15, 2016 in the amount of $14.5205 per $1,000 principal amount of Debentures and will include interest payable from and including the closing of the Offering, which is expected to take place on or about March 1, 2016 (the "**Closing Date**"). Subsequently, quarterly interest payments will be made in the amount of $12.50 per $1,000 principal amount of Debentures. **On the day following the Final Instalment Date, the interest rate payable on the Debentures will fall to an annual rate of 0% and interest will cease to accrue on the Debentures**. Based on a first instalment of $333 per $1,000 principal amount of Debentures, the effective annual yield to and including the Final Instalment Date is 15.0%, and the effective annual yield thereafter is 0%.

If the Final Instalment Date occurs on a day that is prior to the first anniversary of the Closing Date, holders of Debentures who have paid the final instalment on or before the Final Instalment Date will be entitled to receive, on the business day following the Final Instalment Date, in addition to the payment of accrued and unpaid interest to and including the Final Instalment Date, an amount equal to the interest that would have accrued from the day following the Final Instalment Date to and including the first anniversary of the Closing Date had the Debentures remained outstanding and continued to accrue interest until and including such date (the "**Make-Whole Payment**"). No Make-Whole Payment will be payable if the Final Instalment Date occurs on or after the first anniversary of the Closing Date.

Conversion Privilege

At the option of the holder of Debentures and provided that payment of the final instalment has been made, each Debenture will be convertible into common shares of Algonquin ("**Common Shares**") at any time on or after the Final Instalment Date, but prior to the earlier of the date that the Corporation redeems the Debentures or the Maturity Date (as defined in this Prospectus). The conversion price will be $10.60 per Common Share (the "**Conversion Price**"), being a conversion rate of 94.3396 Common Shares per $1,000 principal amount of Debentures, subject to adjustment in certain events. **A holder of Debentures who does not exercise its conversion privilege concurrently with the payment of the final instalment in order to convert its Debentures to Common Shares on the Final Instalment Date will hold a Debenture that pays 0% interest and may be redeemed by the Corporation in whole or in part on any trading day following the Final Instalment Date at a price equal to its principal amount plus any unpaid interest which accrued prior to and including the Final Instalment Date**. See "Details of the Offering".

Prior to the Final Instalment Date, the Debentures may not be redeemed by the Corporation, except that the Debentures will be redeemed by the Corporation at a price equal to their principal amount plus accrued and unpaid interest following the earlier of: (i) notification to holders that the Approval Conditions will not be satisfied; (ii) termination of the Acquisition Agreement in accordance with its terms; and (iii) September 11, 2017 if the Final Instalment Notice has not been given on or before September 8, 2017. Upon any such redemption, the Corporation will pay for each Debenture: (i) $333 plus accrued and unpaid interest to the holder of the Instalment Receipt; and (ii) $667 to the Selling Debentureholder on behalf of the holder of the Instalment Receipt in satisfaction of the final instalment. Under the terms of the Instalment Receipt Agreement, Algonquin has agreed that until such time as the Debentures have been redeemed in accordance with the foregoing or the Final Instalment Date has occurred, the Corporation will maintain readily available capacity under the Revolving Facilities (as defined in this Prospectus), or have cash on hand together with such available capacity, in an amount at least equal to the net proceeds of the first instalment paid on the closing of the Offering (and the exercise of the Over-Allotment Option (as defined in this Prospectus), if applicable). See "Details of the Offering – Debentures – Redemption". After the Final Instalment Date, any Debentures not converted to Common Shares may be redeemed at the option of the Corporation at a price equal to their principal amount plus any unpaid interest which accrued prior to and including the Final Instalment Date. See "Details of the Offering – Debentures – Redemption".

On March 31, 2026 (the "**Maturity Date**"), the Corporation will repay the principal amount of any Debentures not converted and remaining outstanding, in cash. The Corporation may, at its option and without prior notice, satisfy the obligation to pay the principal amount of such Debentures on maturity by delivery of that number of freely tradable Common Shares obtained by dividing the aggregate principal amount of the Debentures then outstanding by 95% of the weighted average trading price of the Common Shares on the Toronto Stock Exchange (the "**TSX**") for the 20 consecutive trading days ending five trading days preceding the Maturity Date (the "**Market Price**").

Price: $1,000 per Debenture to yield 5.00% per annum
(each Debenture is convertible into Common Shares at a Conversion Price of $10.60)

	Price to the Public	Underwriters' Fee(1)	Net Proceeds(2)
Per Debenture			
First Instalment	$ 333.00	$ 20.00	$ 313.00
Final Instalment	$ 667.00	$ 20.00	$ 647.00
Total Per Debenture	$ 1,000.00	$ 40.00	$ 960.00
Total(3)	$ 1,000,000,000	$ 40,000,000	$ 960,000,000

(1) The Underwriters' fee will be paid by the Corporation and is equal to 4.0% of the gross proceeds of the Offering. One-half of the Underwriters' fee is payable on the Closing Date and the remaining one-half is payable on the Final Instalment Date.

(2) Net proceeds are calculated before deducting the expenses of the Offering, estimated at $1,600,000, which will be paid by Algonquin and the Selling Debentureholder.

(3) The Selling Debentureholder has granted to the Underwriters (as defined in this Prospectus) an option (the "**Over-Allotment Option**") to purchase additional Debentures represented by Instalment Receipts equal to up to 15% of the aggregate principal amount of Debentures represented by Instalment Receipts sold on the Closing Date, at a price of $1,000 per Debenture payable on an instalment basis and on the same terms and conditions of the Offering to cover over-allotments, if any, and for market stabilization purposes. The Over-Allotment Option is exercisable in whole or in part at the Underwriters' sole discretion and without obligation, on or prior to the 30th day following the closing of the Offering. If the Over-Allotment Option is exercised in full, the total "Price to the Public", "Underwriters' Fee" and "Net Proceeds" will be $1,150,000,000, $46,000,000 and $1,104,000,000 respectively. This Prospectus qualifies the grant of the Over-Allotment Option and the sale of Debentures represented by Instalment Receipts pursuant to this Prospectus on the exercise of such option. A purchaser who acquires Debentures represented by Instalment Receipts forming part of the Underwriters' over-allocation position acquires those securities under this Prospectus, regardless of whether the position is ultimately filled through the exercise of the Over-Allotment Option or secondary market purchases. Unless otherwise indicated, the disclosure in this Prospectus assumes that the Over-Allotment Option has not been exercised. See "Plan of Distribution".

Underwriters' Position	Maximum Size or Number of Securities Held	Exercise Period	Exercise Price
Over-Allotment Option	Option to purchase up to $150,000,000 aggregate principal amount of Debentures (on an instalment basis)	At any time within 30 days following the closing of the Offering	$1,000 per Debenture payable on an instalment basis of which $333 is payable by the closing of the Over-Allotment Option and $667 is payable on or before the Final Instalment Date

There is currently no market through which the Debentures represented by Instalment Receipts may be sold and purchasers may not be able to resell securities purchased under this Prospectus. This may affect the pricing of the securities in the secondary market, the transparency and availability of trading prices, the liquidity of the securities and the extent of issuer regulation. See "Risk Factors".

This Prospectus qualifies for distribution the Debentures represented by the Instalment Receipts. Algonquin has applied to list the Instalment Receipts (representing the Debentures) and the Common Shares issuable on the conversion of the Debentures on the TSX. Listing will be subject to the Corporation fulfilling all of the requirements of the TSX. **The Corporation has no current intention to list the Debentures for trading on any exchange as it currently anticipates all Debentures will be converted to Common Shares on the Final Instalment Date**. The Corporation's outstanding Common Shares are listed on the TSX under the symbol "AQN". On February 8, 2016, the last trading day prior to the announcement of the Acquisition and the Offering, the closing price of the Common Shares on the TSX was $11.84.

The Debentures will be sold by the Selling Debentureholder to the Underwriters on an instalment basis for a total of $1,000 per Debenture, which price and other terms of the Offering were determined by negotiation between the Corporation, the Selling Debentureholder and the Underwriters. **After a reasonable effort has been made to sell all of the Debentures at the price specified above, the Underwriters may subsequently reduce the selling price to investors from time to time in order to sell any of the Debentures remaining unsold. Any such reduction will not affect the proceeds received by the Selling Debentureholder. See "Plan of Distribution".**

An investment in the Debentures represented by Instalment Receipts, and the Common Shares issuable upon the conversion of Debentures, involves certain risks that should be considered by a prospective purchaser. See "Risk Factors – Risk Factors Relating to the Debentures", "Risk Factors – Risk Factors Relating to the Instalment Receipts" and "Special Note Regarding Forward-Looking Statements".

Each of CIBC World Markets Inc., Scotia Capital Inc., BMO Nesbitt Burns Inc., National Bank Financial Inc., RBC Dominion Securities Inc., TD Securities Inc., Desjardins Securities Inc., Raymond James Ltd., J.P. Morgan Securities Canada Inc., Wells Fargo Securities Canada, Ltd., Industrial Alliance Securities Inc., Canaccord Genuity Corp. and Cormark Securities Inc. are acting as underwriters (collectively, the "**Underwriters**") of the Offering. The Underwriters, as principals, conditionally offer the Debentures represented by Instalment Receipts, subject to prior sale, if, as and when issued, sold and delivered by the Selling Debentureholder to, and accepted by, the Underwriters in accordance with the terms and conditions contained in the Underwriting Agreement (as defined in this Prospectus) referred to under "Plan of Distribution" and subject to the approval of certain legal matters on behalf of the Corporation and the Selling Debentureholder by Blake, Cassels & Graydon LLP and on behalf of the Underwriters by Bennett Jones LLP, Toronto. Subject to applicable laws, the Underwriters may, in connection with the Offering, effect transactions which stabilize or maintain the market price of the Instalment Receipts representing the Debentures or the Common Shares at levels above those which may prevail on the open market. Such transactions, if commenced, may be discontinued at any time. See "Plan of Distribution".

Each of CIBC World Markets Inc., BMO Nesbitt Burns Inc., National Bank Financial Inc., RBC Dominion Securities Inc., TD Securities Inc., Desjardins Securities Inc., J.P. Morgan Securities Canada Inc. and Wells Fargo Securities Canada, Ltd. is an affiliate of a financial institution that has, either solely or as a member of a syndicate of financial institutions, extended (or will extend) credit facilities to, or holds (or will hold) other indebtedness of, the Corporation and/or its subsidiaries, including the Revolving Facilities and the Acquisition Credit Facilities (as defined in this Prospectus). See "Financing the Acquisition". In connection with the Acquisition, Algonquin engaged Wells Fargo Securities, LLC as lead merger advisor and J.P. Morgan Securities LLC as lead financial and strategic advisor. **Consequently, the Corporation and/or the Selling Debentureholder may be considered a "connected issuer" of these Underwriters within the meaning of applicable securities legislation. See "Relationship between Algonquin, the Selling Debentureholder and Certain Underwriters".**

Subscriptions for the Debentures represented by Instalment Receipts will be received subject to rejection or allotment in whole or in part and the right is reserved to close the subscription books at any time without notice. It is expected that the Closing Date will take place on or about March 1, 2016, or such other date as may be agreed upon by the Corporation, the Selling Debentureholder and the Underwriters, but not later than March 10, 2016. The Debentures represented by Instalment Receipts offered hereby are to be taken up by the Underwriters, if at all, on or before a date not later than 42 days after the date of the receipt for the final short form prospectus relating to the Offering.

A book-entry only certificate representing the Instalment Receipts (representing the Debentures) distributed hereunder will be issued in registered form only to CDS Clearing and Depository Services Inc. ("**CDS**") or its nominee and will be deposited with CDS on the Closing Date. Subject to compliance with the provisions of the Instalment Receipt Agreement, as soon as practicable on or after the Final Instalment Date, provided that payment of the final instalment has been made, the global certificate representing the Instalment Receipts will be cancelled and the global certificate representing the Debentures distributed hereunder, pledged to the Selling Debentureholder and held by CST Trust Company, as security agent, will be discharged and released and one or more new global certificates representing the Debentures will be delivered to CDS and registered in the name of CDS or its nominee (as adjusted for Debentures that have been converted into Common Shares on the Final Instalment Date). The Corporation understands that a purchaser of Debentures represented by Instalment Receipts will receive only a customer confirmation from the registered dealer (who is a participant in CDS) from or through whom the Debentures represented by Instalment Receipts are purchased. Except as otherwise stated herein, neither the holders of Instalment Receipts representing Debentures nor the holders of Debentures on or following the Final Instalment Date will be entitled to receive physical certificates representing their ownership thereof, as applicable. See “Details of the Offering”.

In this Prospectus, unless otherwise specified or the context otherwise requires, all dollar amounts are expressed in Canadian dollars.

Masheed Saidi and Dilek Samil, directors of the Corporation, both reside outside of Canada. Each of Ms. Saidi and Ms. Samil has appointed the Corporation as her agent for service of process in Canada. Purchasers are advised that it may not be possible for investors to enforce judgments obtained in Canada against any person or company that is incorporated, continued or otherwise organized under the laws of a foreign jurisdiction or resides outside of Canada, even if the party has appointed an agent for service of process. See “Enforceability of Certain Civil Liabilities”.

The registered and head office of the Corporation is located at 354 Davis Road, Oakville, Ontario, L6J 2X1.

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

*Please refer to the "Glossary of Terms" beginning on page 106 of this preliminary short form prospectus (the "**Prospectus**") for a list of defined terms used herein.*

This Prospectus, including the documents incorporated herein by reference, contains forward-looking information within the meaning of applicable securities laws which reflects management's current expectations regarding: (i) the future growth, results of operations, performance, business prospects and opportunities of the Corporation; (ii) the timing and completion of the contemplated Acquisition; (iii) the benefits and the impact of the Acquisition, the Offering and the Acquisition Credit Facilities on the financial position of the Corporation; and (iv) the future performance, business prospects and opportunities of Empire and the integration of its electric, gas and water utility businesses with the existing operations of Algonquin. These expectations may not be appropriate for other purposes. All forward-looking information is given pursuant to the "safe harbour" provisions of applicable Canadian securities legislation. The words "anticipates", "believes", "budget", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs and is based on information currently available to the Corporation's management.

The forward-looking information in this Prospectus, including the documents incorporated herein by reference, includes, but is not limited to, statements regarding: Algonquin's consolidated net income and cash flow; the growth and diversification of Algonquin's business and earnings base; future annual net income and dividend growth; expansion of Algonquin's business in the United States and elsewhere; the completion of the Acquisition; the expected compliance by Algonquin and its subsidiaries with the regulation of their operations; the expected timing of regulatory decisions; forecasted gross capital expenditures; the nature, timing and costs associated with certain capital projects; the expected impacts on Algonquin of challenges in the global economy; estimated energy consumption rates; expectations related to annual operating cash flows; the expectation that Algonquin will continue to have reasonable access to capital in the near to medium terms; expected debt maturities and repayments; and expectations about increases in interest expense and/or fees associated with credit facilities.

The forward-looking information contained herein pertaining to the Acquisition and the financing thereof, the future performance, business prospects and opportunities of Empire and the integration of its electric, gas and water utility businesses with the existing operations of Algonquin includes, but is not limited to, statements regarding: the expectation that the Acquisition will increase the Corporation's consolidated rate base and total customers; the expectation that the Acquisition will be accretive to Algonquin's earnings per Common Share; the impact of the Acquisition on Algonquin's total assets, net income, growth, access to equity and debt capital markets, credit profile, economies of scale and ability to deploy capital; the stability of Algonquin's net income and overall quality of cash flows; the expectation that Algonquin will benefit from diversification of regulatory jurisdictions; the expectations regarding rate base growth; the expectation that future capital expenditures of Empire will be financed from internally generated cash flows; the expectation that the Acquisition will provide an opportunity to participate in the shift in generation from high carbon sources to low carbon sources as a result of the U.S. government's Clean Power Plan or similar federal or state initiatives; expectations regarding the economic outlook in Missouri and in the U.S. generally; the complementary management teams and corporate cultures of Algonquin and Empire; Empire's labour relations; expectations regarding the nature, timing and costs of capital spending of Algonquin and Empire; the locations of the combined operations after completion of the Acquisition; the expectations with respect to the impact of costs and compliance as a result of new and existing laws, regulations and guidelines, including, but not limited to, environmental matters; the impact of legal proceedings; the financing of the Acquisition, including, but not limited to, the use of the net proceeds of the Offering, the repayments under the Acquisition Credit Facilities and the terms and conditions of the Acquisition Credit Agreements (as defined in this Prospectus); the impact of the Offering, the Acquisition Credit Facilities, the timing and closing of the Acquisition, the conversion of the Debentures into Common Shares, the issuance of Common Shares and changes to the Corporation's long-term debt on the capital structure of the Corporation; the plan of distribution pursuant to the Underwriting Agreement; and the risk factors relating to the Acquisition, the post-Acquisition combined business and operations of the Corporation and Empire, the Instalment Receipts, the Debentures and the Common Shares.

The forecasts and projections that make up the forward-looking information included in this Prospectus are based on assumptions which include, but are not limited to: the timing and completion of the Acquisition; the receipt of Empire Shareholder Approval (as defined in this Prospectus), the required regulatory approvals relating to the Acquisition and other conditions precedent to closing the Acquisition; the payment to the Selling Debentureholder of the aggregate amount of the final instalment; the conversion of all of the Debentures distributed pursuant to this Prospectus into Common Shares on the Final Instalment Date; the realization of the anticipated benefits of the Acquisition to Algonquin, including the expectation that the Acquisition will be accretive to Algonquin's earnings per Common Share; the impact of the Acquisition on Algonquin's total assets, net income, growth, access to equity and debt capital markets, credit profile, economies of scale and ability to deploy capital; that Empire will remain a regulated entity; that the increased contribution from regulated operations will enhance Algonquin's stability and predictability of Adjusted EBITDA (as defined in this Prospectus) and net income and increase the overall quality of cash flows; that enhanced access to equity and debt capital markets and economies of scale will improve the terms upon which the Corporation will fund its future growth projects; that capital expenditure projects will increase Empire's regulated rate base; that Algonquin's experience and expertise in developing renewable power projects and the U.S. Government's Clean Power Plan or similar federal or state initiatives will create opportunities for Empire to participate in the shift from high carbon sources to low carbon sources; that Algonquin and Empire have complementary management teams and corporate cultures and that this will support a smooth combination of the two companies; that Algonquin's Missouri utility operations can benefit from and be managed by Empire management; that Empire will maintain constructive regulatory relationships with state regulatory authorities; the accuracy of the pro forma combined financial information, which does not purport to be indicative of the financial information that will result from the operations of Algonquin on a consolidated basis following the closing of the Acquisition and the completion of the Offering; the ability of Algonquin to successfully integrate the business and operations of Empire into the Algonquin group of companies; the ability of Algonquin to retain key personnel of Empire and its subsidiaries, and the value of such key employees; the amount of borrowings to be drawn down under, and the utilization of, the Acquisition Credit Facilities; the ability of Algonquin to satisfy its liabilities and meet its debt service obligations following completion of the Acquisition; the aggregate amount of the Acquisition-Related Expenses (as defined in this Prospectus); the accuracy and completeness of the Empire public and other disclosure reflected in this Prospectus; the absence of undisclosed liabilities of Empire; the receipt of applicable regulatory approvals and requested rate orders; no material adverse regulatory decisions being received and the expectation of regulatory stability; no significant variability in interest rates; no significant operational disruptions or liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major events; the continued ability to maintain transmission and distribution systems to ensure their continued performance; no severe and prolonged downturn in economic conditions; no significant decline in capital spending; sufficient liquidity and capital resources; the continuation of regulator-approved mechanisms to flow through the commodity cost of natural gas and energy supply costs in customer rates at Algonquin and Empire and their respective subsidiaries and environmental costs at Empire and its subsidiaries in customer rates; the ability to hedge exposures to fluctuations in interest rates, foreign exchange rates, natural gas commodity prices, electricity prices, coal, natural gas and other fuel prices; the price obtainable from time to time for wholesale electricity sales; the cost at which replacement sources of power could be obtained by Empire; the rate of decline in power consumption resulting from energy efficiency programs and customer-oriented generation; the continuation of observed weather patterns and trends; no significant counterparty defaults; the continued competitiveness of electricity pricing when compared with other alternative sources of energy; the continued availability of natural gas, fuel, coal and electricity supply; continuation and regulatory approval of power supply and capacity purchase contracts; the absence of significant changes in government energy plans and environmental laws and regulations that may materially negatively affect the operations and cash flows of Algonquin and/or Empire; the ability of Empire to continue to receive electricity on a cost-effective basis from the generating stations in which it currently owns or has an interest; the amount of capital expenditures which will be required of Empire and its subsidiaries to comply with current and future environmental regulations; no material change in public policies and directions by governments that could materially negatively affect Algonquin, Empire and their respective subsidiaries; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; no material decrease in market energy sales prices; retention of existing service areas; continued maintenance of information technology infrastructure; favourable labour relations; and sufficient human resources to deliver service and execute the capital program.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors which could cause results or events to differ from current expectations include, but are not limited to: derivative financial instruments, including, but not limited to, hedging availability; commodity price and availability risk; foreign exchange risk; interest rate risk; commercial relationship risk; credit risk; labour risk; weather risk;

regulatory risk; environmental risk; capital market risk, including, but not limited to, economic conditions, cost of financing, capital resources and liquidity risk; construction and development risks; inability to complete the Offering; inability to complete the Acquisition; an increase in the cash purchase price of the Acquisition; uncertainty regarding the length of time required to complete the Acquisition; the anticipated benefits of the Acquisition may not materialize or may not occur within the time periods anticipated by the Corporation; impact of significant demands placed on the Corporation as a result of the Acquisition; failure by the Corporation to repay the final instalment; failure to repay the Acquisition Credit Facilities; potential unavailability of the Acquisition Credit Facilities; alternate sources of funding that would be used to replace the Acquisition Credit Facilities may not be available when needed; lack of control by the Corporation of Empire and its subsidiaries prior to the closing of the Acquisition; impact of the Acquisition-Related Expenses; accuracy and completeness of Empire's publicly disclosed information; increased indebtedness of Algonquin after the closing of the Acquisition; the Acquisition and related financing, including the Offering, could result in a downgrade of credit ratings of the Corporation, Empire and/or their subsidiaries; historical and pro forma combined financial information may not be representative of future performance; potential undisclosed liabilities of Empire and its subsidiaries; ability to retain key personnel of Empire following the Acquisition; operating and maintenance risks; risks associated with changes in economic conditions; developments in technology could reduce demand for electricity, gas and water; changes in customer energy usage patterns; risk of failure of information technology infrastructure and cybersecurity; disruption of fuel supply; natural disasters or other catastrophic events; impairment testing of certain long-lived assets could result in impairment charges; indebtedness of Empire; risks relating to the Instalment Receipts, the Debentures and the Common Shares; unanticipated maintenance and other expenditures; risk associated with the continuation, renewal, replacement and/or regulatory approval of power supply and capacity purchase contracts; risks associated with pension plan performance and funding requirements; regulatory and government decisions including, but not limited to, changes to environmental, financial reporting and tax legislation and regulations; risk of loss of licences and permits; risk of loss of service area; market energy sales prices; changes to the regulation of rates Empire charges its utility customers; risk of condemnation; and adverse publicity and reputational risk. For additional information with respect to the Corporation's risk factors and risk factors relating to the post-Acquisition business of Algonquin, the operations of Algonquin and Empire, the Acquisition, the Debentures, the Instalment Receipts and the Common Shares, reference should be made to the section of this Prospectus entitled "Risk Factors" and to the documents incorporated herein by reference and to the Corporation's continuous disclosure materials filed from time to time with Canadian securities regulatory authorities.

All forward-looking information in this Prospectus and in the documents incorporated herein by reference is qualified in its entirety by the above cautionary statements and, except as required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise.

DOCUMENTS INCORPORATED BY REFERENCE

The disclosure documents of the Corporation listed below and filed with the appropriate securities commissions or similar regulatory authorities in each of the provinces of Canada are specifically incorporated by reference into and form an integral part of this Prospectus:

(i) the Annual Information Form of Algonquin dated March 30, 2015 for the year ended December 31, 2014 (the "**AIF**");

(ii) the audited comparative consolidated financial statements of Algonquin as at and for the years ended December 31, 2014 and December 31, 2013, together with the auditors' report thereon;

(iii) Management's Discussion and Analysis of Algonquin for the year ended December 31, 2014 (the "**Annual MD&A**");

(iv) the unaudited interim comparative consolidated financial statements of Algonquin as at and for the three and nine months ended September 30, 2015 and September 30, 2014;

(v) Management's Discussion and Analysis of Algonquin for the three and nine months ended September 30, 2015 (the "**Q3 MD&A**");

(vi) the Management Information Circular of Algonquin filed on SEDAR on June 4, 2015 in respect of Algonquin's annual meeting of shareholders held on June 30, 2015;

(vii) the template version of the term sheet dated February 9, 2016 and the template version of the investor presentation dated February 9, 2016, each filed on SEDAR in connection with the Offering (collectively, the "**Marketing Materials**"); and

(viii) the material change report dated February 10, 2016 in respect of the Acquisition and the Offering.

Any documents of the type referred to above (other than confidential material change reports), any document filed by Algonquin that specifically states that such document is incorporated by reference into this Prospectus and any other documents required under applicable securities laws to be incorporated by reference into this Prospectus, if filed by Algonquin with the provincial securities commissions or similar authorities in Canada after the date of this Prospectus and prior to the termination of the Offering, shall be deemed to be incorporated by reference into this Prospectus.

Any statement contained in a document incorporated or deemed to be incorporated by reference in this Prospectus shall be deemed to be modified or superseded for purposes of this Prospectus to the extent that a statement contained herein, or in any other subsequently filed document which also is incorporated or is deemed to be incorporated herein by reference, modifies or supersedes such statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of a modifying or superseding statement will not be deemed to be an admission for any purpose that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it was made. Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute a part of this Prospectus.

Copies of the documents incorporated herein by reference may be obtained on request without charge from the Corporate Secretary of the Corporation at 354 Davis Road, Oakville, Ontario, L6J 2X1, telephone (905) 465-4500, and are also available electronically at www.sedar.com. The information contained on, or accessible through, any of these websites is not incorporated by reference into this Prospectus and is not, and should not be considered to be, a part of this Prospectus, unless it is explicitly so incorporated.

MARKETING MATERIALS

The Marketing Materials are not part of this Prospectus to the extent that the contents of the Marketing Materials have been modified or superseded by a statement contained in this Prospectus. Any template version of "marketing materials" (as defined in National Instrument 41-101 – *General Prospectus Requirements*) filed after the date of this Prospectus and before the termination of the distribution under the Offering (including any amendments to, or an amended version of, the Marketing Materials) are deemed to be incorporated into this Prospectus.

ELIGIBILITY FOR INVESTMENT

In the opinion of Blake, Cassels & Graydon LLP, counsel to Algonquin and the Selling Debentureholder, and Bennett Jones LLP, counsel to the Underwriters, provided that, on the date hereof, Algonquin is a "public corporation" for the purposes of the Tax Act or the Common Shares are listed on a "designated stock exchange" for the purposes of the Tax Act (which currently includes the TSX), the Debentures represented by Instalment Receipts and the Common Shares issuable on the conversion or maturity of the Debentures, if issued on the date hereof, would be qualified investments under the Tax Act as of the date hereof for a trust governed by a registered retirement savings plan ("**RRSP**"), a registered retirement income fund ("**RRIF**"), a registered education savings plan, a deferred profit sharing plan ("**DPSP**"), a registered disability savings plan and a tax-free savings account ("**TFSA**") (collectively, "**Exempt Plans**"), except, in the case of the Debentures, a DPSP to which Algonquin, or a corporation that does not deal at arm's length with Algonquin, has made a contribution. In addition, Exempt Plans (including particularly depositary RRSPs and RRIFs) should have regard to any restrictions (including restrictions on the pledging of plan assets) that may be included in the provisions of their particular Exempt Plan.

Notwithstanding the foregoing, if the Debentures or the Common Shares are a "prohibited investment" (as defined in the Tax Act) for a trust governed by a TFSA, RRSP or RRIF, the holder or annuitant thereof, as the case may be, will be subject to a penalty tax as set out in the Tax Act. The Debentures and Common Shares will not be a prohibited investment for a TFSA, RRSP or RRIF provided the holder or annuitant of such Exempt Plan, as the case may be, (i) deals at arm's length with Algonquin, for purposes of the Tax Act, and (ii) does not have a "significant interest" (as defined in the prohibited investment rules in the Tax Act) in Algonquin. In addition, Common Shares will not be a "prohibited investment" if the Common Shares are "excluded property" (as defined in the Tax Act for this purpose) for trusts governed by a TFSA, RRSP and RRIF.

Holders or annuitants should consult their own tax advisors with respect to whether the Instalment Receipts, Debentures or Common Shares would be prohibited investments (including with respect to whether the Common Shares would be excluded property) and whether they otherwise comply with any restrictions that may apply to particular Exempt Plans.

PRESENTATION OF FINANCIAL INFORMATION

The financial statements of the Corporation included in this Prospectus are reported in Canadian dollars and have been prepared in accordance with Generally Accepted Accounting Principles in the United States ("**U.S. GAAP**"). All financial information of Empire included in this Prospectus as at December 31, 2014 is reported in U.S. dollars and has been derived from audited historical financial statements of Empire that were prepared in accordance with U.S. GAAP. All financial information of Empire included in this Prospectus as at September 30, 2015 is reported in U.S. dollars and has been derived from unaudited historical financial statements of Empire that were prepared in accordance with U.S. GAAP. The assets and liabilities of Empire shown in the unaudited pro forma consolidated balance sheet of the Corporation as at September 30, 2015 are reported in Canadian dollars and reflect the U.S. dollar-to-Canadian dollar period-end closing exchange rate. The revenues and expenses of Empire shown in the unaudited pro forma consolidated statements of earnings of the Corporation for the nine month period ended September 30, 2015 and for the year ended December 31, 2014 are reported in Canadian dollars and reflect the average U.S. dollar-to-Canadian dollar exchange rates for such periods. Financial information in this Prospectus that has been derived from the unaudited pro forma consolidated financial statements has been translated to Canadian dollars on the same basis. Certain tables in this Prospectus may not add due to rounding.

Certain financial measures of Algonquin are used in this Prospectus that do not have standardized meanings under U.S. GAAP and may not be comparable to similar measures presented by other entities. Such non-U.S. GAAP measures are calculated by adjusting certain U.S. GAAP measures for specific items that Algonquin believes are significant, but not reflective of the underlying operations of the Corporation.

Adjusted EBITDA

Earnings before interest, income taxes, depreciation and amortization ("**EBITDA**") is a non-U.S. GAAP financial measure used by many investors to compare companies on the basis of ability to generate cash from operations.

Adjusted earnings before interest, taxes, depreciation and amortization ("**Adjusted EBITDA**") is a non-U.S. GAAP financial measure used in this Prospectus in respect of Algonquin. Algonquin uses Adjusted EBITDA to assess its operating performance 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. Algonquin adjusts for these factors as they may be non-cash, unusual in nature and are not factors used by management for evaluating the operating performance of the Corporation. Algonquin believes that presentation of this measure will enhance an investor's understanding of the Corporation'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 U.S. GAAP. A reconciliation of Adjusted EBITDA to net earnings can be found for the three and nine months ended September 30, 2015 at pages 29-30 of the Q3 MD&A and for the year ended December 31, 2014 at pages 36-37 of the Annual MD&A, both of which are incorporated by reference into this Prospectus.

Adjusted Funds from Operations

Adjusted Funds from Operations ("**Adjusted Funds from Operations**") is a non-U.S. GAAP measure used in this Prospectus in respect of Algonquin. Adjusted Funds from Operations is a non-U.S. 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 Algonquin can be impacted positively or negatively by changes in working capital balances, acquisition expenses, litigation expenses and 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. Algonquin 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 Algonquin. Algonquin believes that analysis and presentation of Adjusted 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 U.S. GAAP. A reconciliation of Adjusted Funds from Operations to cash flows from operating activities can be found for the three and nine months ended September 30, 2015 at page 31 of the Q3 MD&A and for the year ended December 31, 2014 at page 39 of the Annual MD&A, both of which are incorporated by reference into this Prospectus.

Additional information regarding non-U.S. GAAP measures used by Algonquin can be found at pages 1-3 of the Q3 MD&A and the Annual MD&A.

CAUTION REGARDING UNAUDITED PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS

This Prospectus contains the unaudited pro forma consolidated balance sheet as at September 30, 2015 and consolidated statements of earnings of the Corporation for the nine month period ended September 30, 2015 and for the year ended December 31, 2014, giving effect to: (i) the Offering, assuming no exercise of the Over-Allotment Option; (ii) the issuance of Common Shares upon the conversion of the Debentures on the Final Instalment Date; (iii) the Acquisition Credit Facilities that will be drawn on closing of the Acquisition; and (iv) the completion of the Acquisition. Such unaudited pro forma consolidated financial statements have been prepared using certain of the

Corporation's and Empire's respective financial statements as more particularly described in the notes to such unaudited pro forma consolidated financial statements. In preparing such unaudited pro forma consolidated financial statements, Algonquin has had limited access to the non-public books and records of Empire and makes no representation or warranty as to the accuracy or completeness of such information provided by Empire, including the financial statements of Empire that were used to prepare the unaudited pro forma consolidated financial statements. Such unaudited pro forma consolidated financial statements are not intended to be indicative of the results that would actually have occurred, or the results expected in future periods, had the events reflected herein occurred on the dates indicated. Actual amounts recorded upon the finalization of the purchase price allocation under the Acquisition may differ from such unaudited pro forma consolidated financial statements. Since the unaudited pro forma consolidated financial statements have been developed to retroactively show the effect of a transaction that has or is expected to occur at a later date (even though this was accomplished by following generally accepted practice using reasonable assumptions), there are limitations inherent in the very nature of pro forma data. The data contained in the unaudited pro forma consolidated financial statements represents only a simulation of the potential impact of the Acquisition. Undue reliance should not be placed on such unaudited pro forma consolidated financial statements. See "Special Note Regarding Forward-Looking Statements" and "Risk Factors".

CURRENCY

In this Prospectus, unless otherwise specified or the context otherwise requires, all dollar amounts are expressed in Canadian dollars. References to "dollars", "$" or "Cdn$" are to lawful currency of Canada. References to "U.S. dollars" or "US$" are to lawful currency of the United States of America.

The following table sets forth, for each of the periods indicated, the noon exchange rate, the average noon exchange rate and the high and low noon exchange rates of one U.S. dollar in exchange for Canadian dollars as reported by the Bank of Canada.

	Year ended December 31,			Nine months ended September 30,	
	2014	**2013**	**2012**	**2015**	**2014**
High	1.1643	1.0697	1.0418	1.3413	1.1251
Low	1.0614	0.9839	0.9710	1.1728	1.0614
Average	1.1045	1.0299	0.9996	1.2600	1.0942
Period End	1.1601	1.0636	0.9949	1.3394	1.1208

On February 12, 2016, the noon exchange rate as reported by the Bank of Canada was US$1.00 = $1.3835.

DEFINED TERMS

For an explanation of certain terms and abbreviations used in, and conversions applicable to, this Prospectus, reference is made to the "Glossary of Terms" beginning on page 106 of this Prospectus.

Unless otherwise indicated by the context, "Empire" means the parent company, The Empire District Electric Company, and its subsidiaries, and references to individual subsidiaries of The Empire District Electric Company refer to that subsidiary company and its respective subsidiaries.

THIRD PARTY SOURCES AND INDUSTRY DATA

This Prospectus contains information from publicly available third party sources as well as industry data prepared by the Corporation's management on the basis of its knowledge of the regulated electricity, gas, water and wastewater utility industry in which Algonquin operates (including management's estimates and assumptions relating to the industry based on that knowledge). Management's knowledge of the regulated utility industry has been developed through its experience and participation in the industry. Management believes that its industry data is accurate and that its estimates and assumptions are reasonable, but there can be no assurance as to the accuracy or completeness of this data. Third-party sources generally state that the information contained therein has been obtained from sources believed to be reliable, but there can be no assurance as to the accuracy or completeness of included information. Although management believes it to be reliable, none of Algonquin, the Selling Debentureholder or the Underwriters have independently verified any of the data from third-party sources referred to in this Prospectus or analyzed or verified the underlying studies or surveys relied upon or referred to by such sources, or ascertained the underlying economic assumptions relied upon or referred to by such sources.

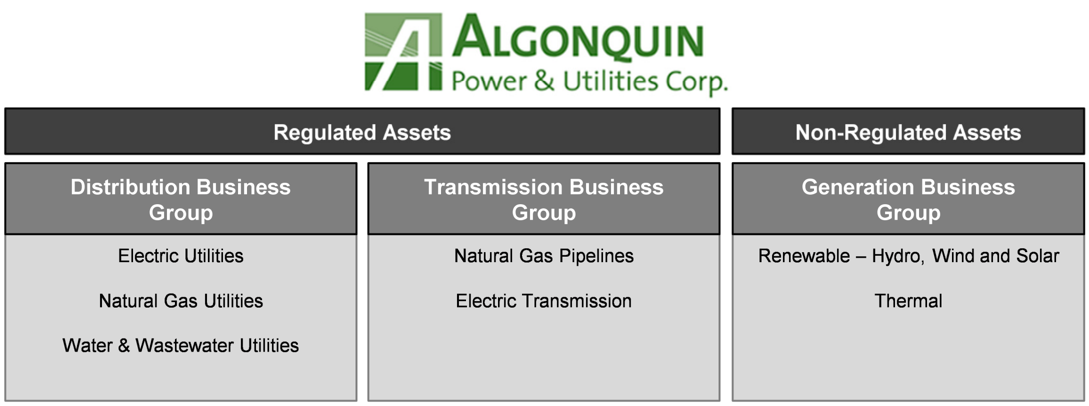
PROSPECTUS SUMMARY

The following information is a summary only and is to be read in conjunction with, and is qualified in its entirety by, the more detailed information and financial data and statements appearing elsewhere in this Prospectus and in the documents incorporated herein by reference.

ALGONQUIN

Algonquin is incorporated under the *Canada Business Corporations Act* ("**CBCA**"). Algonquin owns and operates a diversified portfolio of regulated and non-regulated generation, distribution and transmission utility assets in North America.

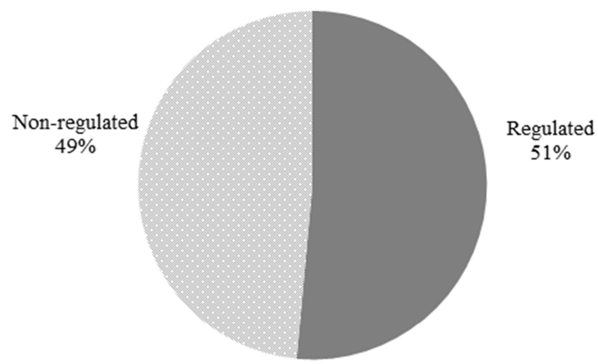
Algonquin's operations are organized across three business units consisting of Generation, Transmission and Distribution. The Generation Business Group ("**Generation Group**") owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation utility assets; the recently 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.



For the twelve months ended September 30, 2015, regulated assets contributed 51% of Algonquin's Adjusted EBITDA (as defined in this Prospectus), with non-regulated assets contributing the balance of 49%. Over the five years ended September 30, 2015, the Corporation's annual Adjusted EBITDA has grown from $97.2 million to $350.1 million.

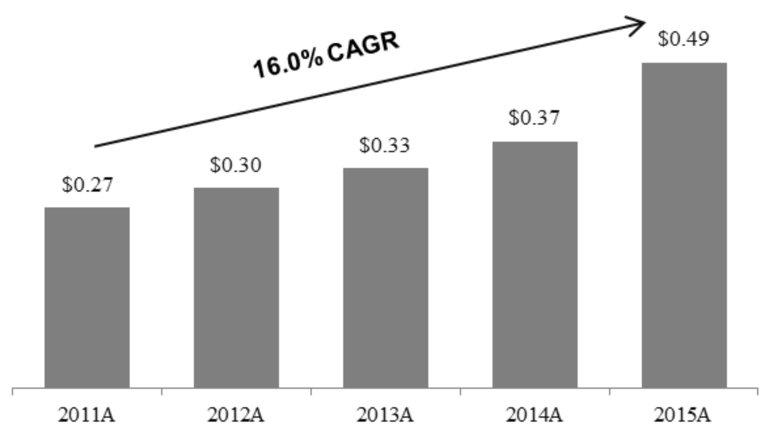
Algonquin Regulated vs Non-Regulated Adjusted EBITDA

For the twelve months ended September 30, 2015



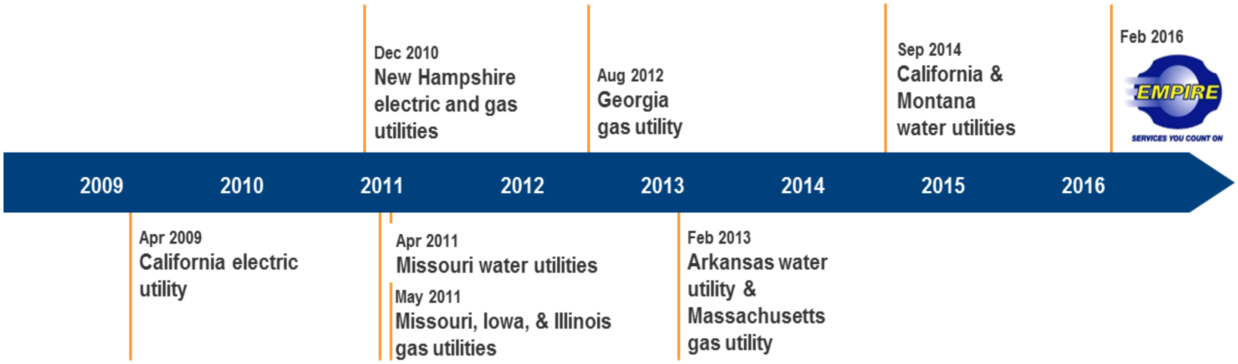
Over the five years from September 30, 2010 to September 30, 2015, Algonquin has significantly grown its revenues, Adjusted EBITDA and net income, leading to a total shareholder return of approximately 24.6% per annum. Over the same period, Algonquin has increased its annualized dividend from $0.24 to US$0.385 per Common Share. As at February 12, 2016, the US$0.385 denominated annualized dividend, when converted at the spot exchange rate of US$1.00 = $1.3835, equates to a Canadian dollar equivalent of $0.533 per Common Share.

Dividend Growth History (C$)(1)



(1) Algonquin commenced declaring dividends in US$ as of August 2014. US$ dividends are converted to Canadian dollars at the Bank of Canada noon rate on the date payable.

Algonquin has substantial experience in combining newly acquired businesses with existing operations. In part due to this experience, management believes that integration of Empire and Algonquin should be smooth, and that leveraging best practices from each entity may contribute to enhanced service for customers and ratepayers. Algonquin's recent acquisitions of electric, gas and water utilities are depicted in the timeline below.



See "Recent Developments" for further information on the Corporation's most recently completed acquisition.

Generation 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, solar and thermal facilities with a combined gross generating capacity of approximately 120 MW, 700 MW, 35 MW and 335 MW, respectively. Approximately 83% of the electrical output from the hydroelectric, wind, solar and thermal generating facilities is sold pursuant to long-term contractual arrangements, which have a weighted average remaining contract life of 13 years.

The Generation Group also has a portfolio of development projects, which are expected to be commissioned between 2016 and 2018 and will add approximately 711 MW of generation capacity from wind and solar powered generating stations with an average contract life of 20 years.

Distribution Group

The Distribution Group operates diversified rate regulated electricity, natural gas, water distribution and wastewater utilities, providing services to approximately 560,000 customers. The Distribution Group provides safe, high quality and reliable services to its ratepayers through its portfolio of utility systems in the United States and delivers stable and predictable earnings to the Corporation. In addition to encouraging and supporting organic growth within its service territories, the Distribution Group delivers continued growth in earnings through accretive acquisitions 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 customers. 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 customers. The Distribution Group's regulated water distribution and wastewater collection utility systems are located in the States of Arizona, Arkansas, California, Illinois, Missouri, Montana and Texas and together serve approximately 177,000 customers.

Transmission Group

In 2014, Algonquin 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 Corporation believes that the creation of the Transmission Group complements the growth of both the Generation and Distribution Groups.

The Transmission Group is currently participating in two related joint venture pipeline projects with Kinder Morgan, Inc. (“**Kinder Morgan**”) in connection with Kinder Morgan’s Northeast Energy Direct project to serve New England natural gas markets. The Transmission Group is participating with Kinder Morgan, through a newly formed entity (“**Northeast Expansion LLC**”), in the development, construction and ownership of a natural gas transmission pipeline to be located between Wright, New York and Dracut, Massachusetts (the “**Market Path Project**”). The Transmission Group has initially subscribed for a 2.5% interest in Northeast Expansion LLC. The Transmission Group expects to invest approximately $5.0 million (US$3.8 million) in the Market Path Project in 2016. As proposed, the potential investment could exceed US$300 million over a three-year period if the Transmission Group elects to increase its interest. In addition, the Transmission Group is also participating, in partnership with Kinder Morgan and through a newly formed entity (the “**Northeast Supply Pipeline LLC**”), in the development of a gas pipeline traversing New York State, between Wright, New York and northeast Pennsylvania (the “**Supply Path Project**”). The Transmission Group has initially subscribed for a 4.0% interest in the Supply Path Project, with total capital investment potential estimated to be up to US$200 million over the next three years if the Transmission Group elects to increase its interest. Subject to certain prescribed conditions, Algonquin may elect to increase its participation levels by up to 10% in each project.

THE ACQUISITION

Acquisition Overview

On February 9, 2016, AcquisitionCo and Merger Sub entered into the Acquisition Agreement with Empire which provides for, among other things, the acquisition by AcquisitionCo of Empire through the Merger (as defined in this Prospectus). The aggregate purchase price for the Acquisition is approximately US$2.4 billion, comprised of approximately US$1.5 billion in cash payable on closing and the assumption of approximately US$0.9 billion of debt. The Acquisition is subject to receipt of Empire Shareholder Approval (at its shareholder meeting expected to occur in the second or third quarter of 2016) and certain regulatory and governmental approvals, including the expiration or termination of any applicable waiting period under the HSR Act, CFIUS Approval, the approval by each of FERC, the FCC and the State Commissions (as defined in this Prospectus), and the satisfaction of other customary closing conditions. The closing of the Acquisition is currently expected to occur in the first quarter of 2017.

Based on pro forma financial information as at September 30, 2015, following the Acquisition, Algonquin’s total assets will increase from approximately $4.8 billion to approximately $8.9 billion and the percentage of its Adjusted EBITDA that is regulated Adjusted EBITDA is expected to increase from approximately 51% to approximately 72%. Following the Acquisition, the regulated utility subsidiaries of Algonquin will serve approximately 778,000 customers.

Algonquin’s approach to operating its regulated utilities is to build a strong local presence in each market resulting in a strong local customer service presence, including local call centres and walk-in store fronts. Algonquin also engages locally with the regulators in each of its regulatory jurisdictions creating strong, mutually constructive regulatory relationships that benefit all stakeholders, including creating value for customers and investment in local communities in which its utilities operate.

With respect to Empire’s operations, Algonquin intends to maintain Empire’s existing local presence, including existing service centres, call contact centres, customer service offices and local business and community representatives. Algonquin will continue to invest in local communities, including maintaining Empire’s existing headquarters location in Joplin, Missouri. Algonquin also expects to retain Empire’s existing management team, allowing local managers to continue being responsive to employees, customers and regulators and contributing to a smooth transition to Algonquin ownership which is seamless to customers and regulators.

Empire Overview

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, with approximately 218,000 customers in Missouri, Kansas, Oklahoma, and Arkansas. Empire, a Kansas corporation organized in 1909, is an operating public utility with its common stock listed on the NYSE under the ticker symbol “EDE”.

The vertically-integrated regulated electricity operations of Empire represent the majority of its operating revenues and assets. For the year ended December 31, 2014, approximately 91% of Empire's revenues were attributable to its electricity operations, with approximately 8% of revenues attributable to its natural gas subsidiary, and approximately 1% attributable to its fiber optics business.

Empire's electric operations cover a service territory of approximately 10,000 square miles, located principally in southwestern Missouri, and also include smaller areas in southeastern Kansas, northeastern Oklahoma and northwestern Arkansas. Empire supplies electric service to customers in 119 incorporated communities and to various unincorporated areas and at wholesale to four municipally-owned distribution systems. The largest urban area served is the city of Joplin, Missouri, and its immediate vicinity, with a population of approximately 160,000. As of December 31, 2014, Empire's electric operations served approximately 170,000 customers.

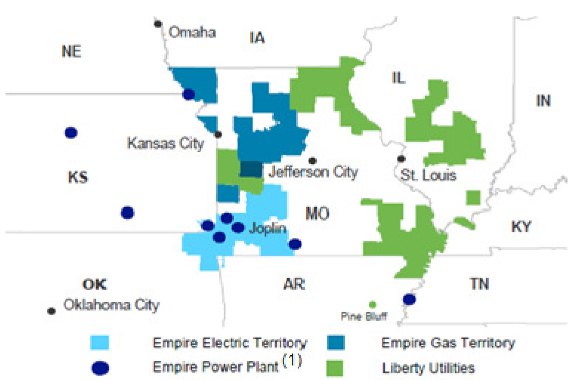
In its electric service territories, Empire operates under franchise agreements having original terms of a minimum of 20 years in virtually all of the incorporated communities. Approximately 55% of the electric operating revenues in 2014 were derived from incorporated communities with franchises having at least 10 years remaining and approximately 15% were derived from incorporated communities in which the franchises have remaining terms of 10 years or less. Although the franchise agreements contain no renewal provisions, in recent years, Empire has obtained renewals of all expiring electric franchises prior to the expiration dates.

Empire's gas operations serve customers in northwest, north central and west central Missouri. As of December 31, 2014, the gas operations served approximately 43,500 customers. Empire provided natural gas distribution to 48 communities and 422 transportation customers as of December 31, 2014. The largest urban area served by Empire's gas operations is the city of Sedalia with a population of over 20,000. Empire operates under gas franchises having original terms of 20 years in virtually all of the incorporated communities. As of December 31, 2014, 18 of the gas franchises had 10 years or more remaining on their respective terms and 26 of the gas franchises had less than 10 years remaining on their respective terms. Although the franchise agreements contain no renewal provisions, Empire has obtained renewals of all expiring gas franchises prior to the expiration dates.

Empire's other segment consists of a fiber optics business. As of December 31, 2014, Empire's fiber optics business served 121 customers.

Empire's operating revenue in fiscal 2014 totalled approximately US$652 million and for the nine-month period ended September 30, 2015, totalled approximately US$469 million. As of September 30, 2015, Empire had total assets of approximately US$2.5 billion. Empire operates its businesses as three segments: electric, gas and other (consisting of its fiber optics business). Empire's gross operating revenues in 2014 were derived as follows: 90.8% from electric segment sales (including 0.3% from the sale of water); 8.0% of from gas segment sales; and 1.2% from its other segment sales.

The following map depicts the service territories and generating operations of Empire and its regulated utility subsidiaries, as well as the regional operations of Algonquin's regulated distribution business which operates through Liberty Utilities Co. ("**Liberty Utilities**") and its subsidiaries.



(1) Empire has PPAs (as defined in this Prospectus) in place in respect of two windfarms located in Kansas (depicted in the map above). Empire does not have an ownership interest in either windfarm.

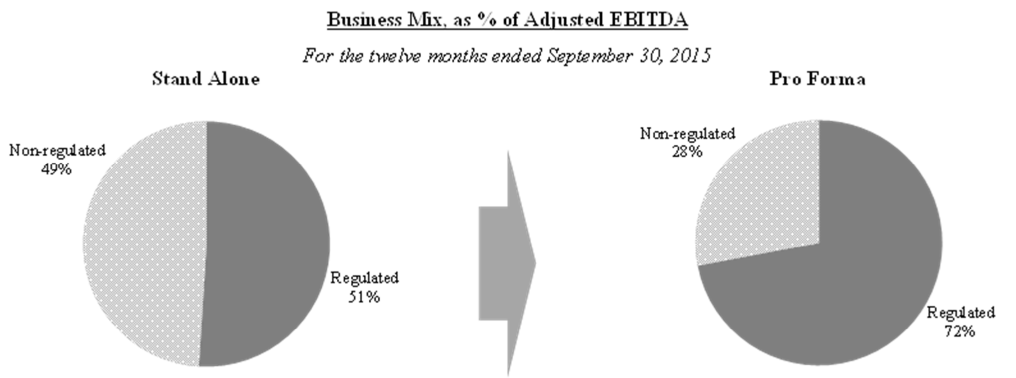
Acquisition Highlights

Accretive to Earnings and Adjusted Funds from Operations per Common Share

Management expects the Acquisition will be accretive to Algonquin's earnings per Common Share in the first full year following closing of the Acquisition. Management estimates the Acquisition to be approximately 7% - 9% accretive to Algonquin's earnings per Common Share over a three-year period following completion of the Acquisition, excluding one-time Acquisition-Related Expenses, and assuming a stable currency exchange environment. Management also expects that the Acquisition will be approximately 12% - 14% accretive to Algonquin's Adjusted Funds from Operations per Common Share in the first full year following closing of the Acquisition, excluding one-time Acquisition-Related Expenses, and assuming a stable currency exchange environment. Such material accretion is forecast to remain robust notwithstanding a scenario in which the Canadian dollar strengthens. Management expects the Acquisition to provide additional support for Algonquin's 10% annual dividend growth target through 2019.

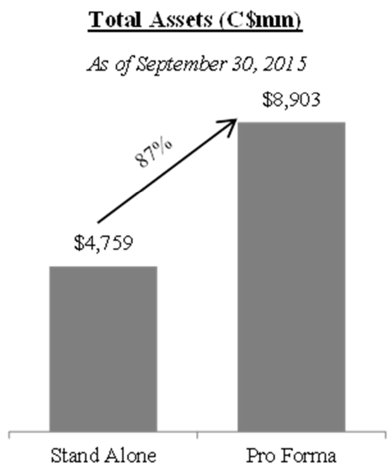
Shift in Business Mix towards Regulated Operations

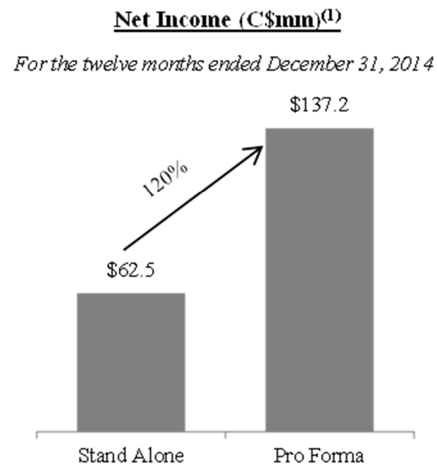
The Acquisition represents an opportunity to increase the contribution of regulated utility operations to Algonquin. As a result of the Acquisition, regulated utility operations will represent 72% of Adjusted EBITDA from 51% on a stand-alone basis for the period ending September 30, 2015. Management anticipates that the increased contribution from regulated operations will enhance Algonquin's stability and predictability of Adjusted EBITDA and net income and increase the overall quality of cash flows. This shift in business mix as a percentage of Adjusted EBITDA is shown below.



Increased Operating Scale

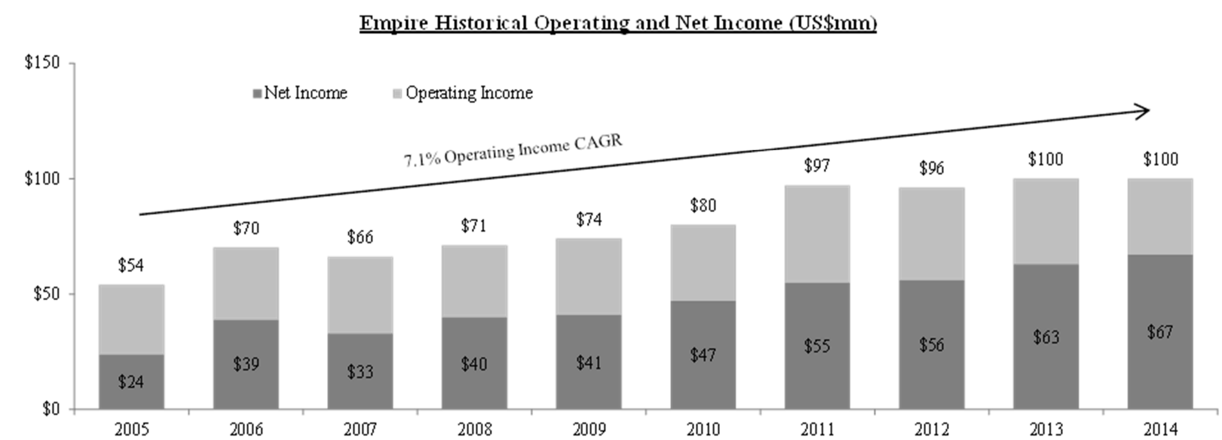
As a result of the Acquisition, Algonquin's enterprise value will increase by approximately 78%. Post-Acquisition, on a pro forma basis as at September 30, 2015 total assets will increase from approximately $4.8 billion to approximately $8.9 billion and net income for the twelve months ended December 31, 2014 will increase from approximately $62.5 million to $137.2 million. Management believes that the Acquisition will enhance Algonquin's access to equity and debt capital markets and economies of scale, which is expected to improve the terms upon which the Corporation will fund its future growth projects. The following charts illustrate Algonquin's total assets and net income on a stand-alone and pro forma basis, as at September 30, 2015 and for the twelve months ended December 31, 2014, respectively, to reflect the increased scale resulting from completion of the Acquisition.

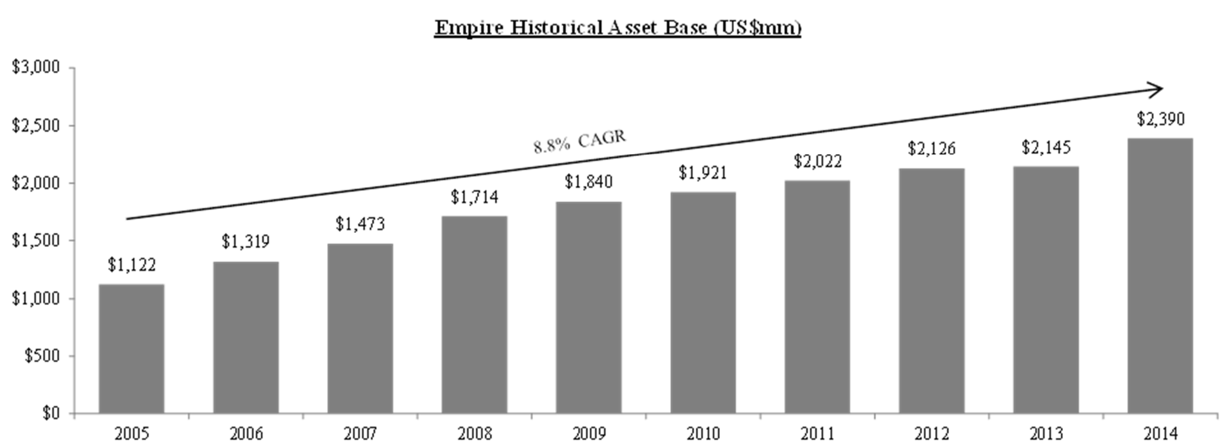




(1) Net earnings attributable to Algonquin.

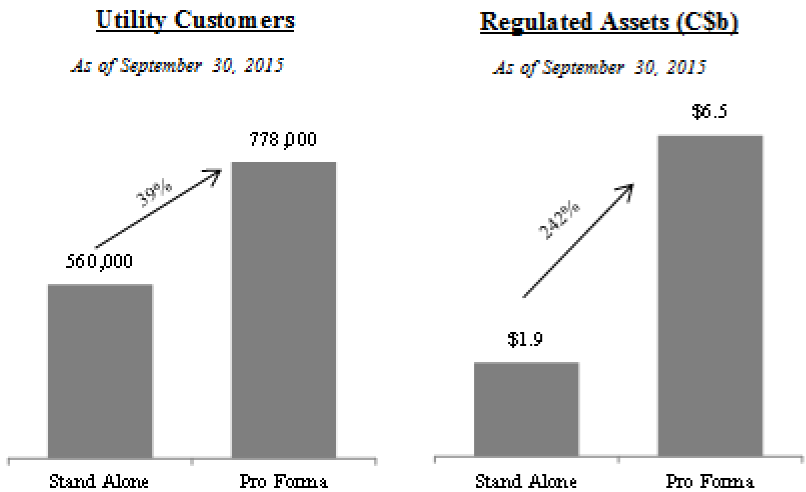
Management expects the Acquisition to produce attractive, predictable earnings growth as a result of the expanded asset base. From 2005 to 2014 Empire achieved a strong CAGR (as defined in this Prospectus) of its operating and net income and asset base, as illustrated in the charts below.





Diversification of Regulated Operations

The Acquisition adds a large profitable regulated distribution and generation business, increasing the Corporation's scale, diversity of customers and geographies of service. Following the Acquisition, Algonquin's regulated operations will have pro forma total assets of $6.5 billion, will operate regulated utilities across thirteen U.S. states and serve approximately 778,000 utility customers, representing an increase of $3.3 billion, two U.S. states and 218,000 utility customers.



Consistent with the Corporation's diversification and growth strategy, its operations will be further diversified across existing and new regulatory jurisdictions and geographies of Missouri, Arkansas, Kansas and Oklahoma. The Acquisition will result in balanced diversified regulated operations across electric, natural gas and water/wastewater utilities.

Constructive Regulatory Jurisdictions

Nearly all of Empire's regulated utility operations are in regulatory jurisdictions familiar to Algonquin from its existing regulated utility operations. For the year ended December 31, 2014, approximately 91% of Empire's retail revenues came from Missouri where Empire has an established and constructive regulatory relationship with the Missouri Public Service Commission ("**MPSC**"). Empire successfully obtained MPSC approval to acquire its regulated natural gas utility in 2006 and it has had successful rate case outcomes, including the use of various trackers for some operations and maintenance cost, as well as pension and retiree healthcare obligations all of which has served to reduce regulatory lag. Furthermore, the Missouri legislature has recently discussed the *21st Century Grid Modernization and Stabilization Act*, a utility industry supported legislative initiative which, if implemented, would be expected to further reduce regulatory lag.

All of Empire's jurisdictions have a fuel recovery mechanism, whereby any changes in fuel and purchased power expense are passed through to customers.

Missouri also provides for an Infrastructure System Replacement Surcharge for gas utilities which allows for the immediate recovery of costs related to the replacement of gas distribution system infrastructure without requiring a rate case. At present, Missouri legislators have introduced a proposed bill which would create a Performance Based Ratemaking ("**PBR**") regulatory construct for electric utilities in Missouri. Under a PBR, the electric utilities could have the potential to seek annual rate adjustments for invested capital and inflationary increases.

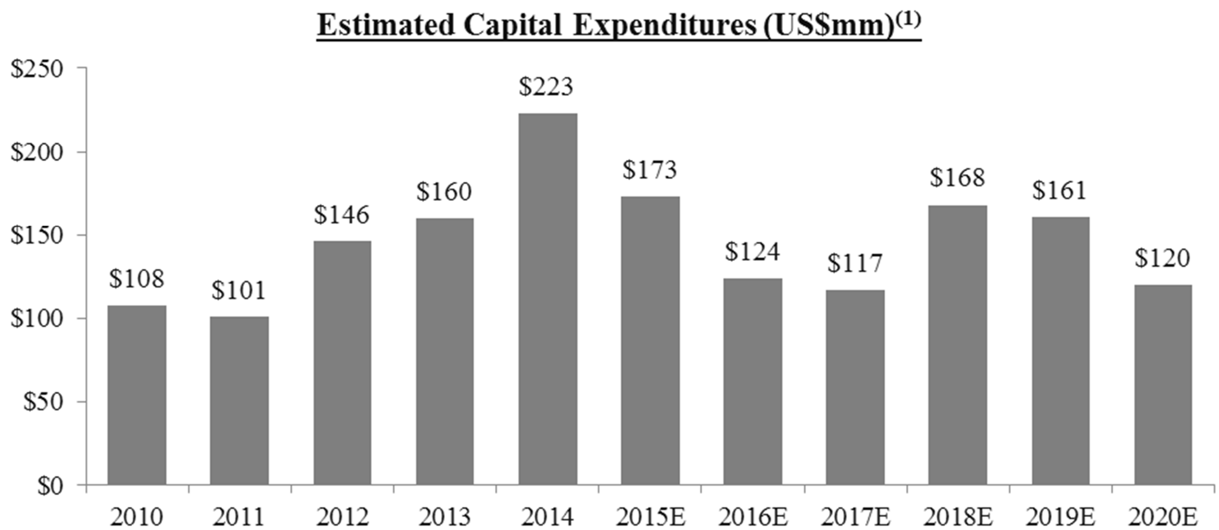
A recent statute was passed in Oklahoma which allows multi-jurisdictional companies such as Empire, who serve less than 10% of total customers within the State of Oklahoma, to benefit from rate reciprocity such that Empire is able to charge its Missouri rates to its customer base in Oklahoma, subject to regulatory approval.

Similar to Missouri, Arkansas has recently enacted legislation which allows utilities to seek PBR structures and apply for annual rate increases to reflect increased investments and inflation.

In Kansas, Empire has maintained constructive regulatory relationships and has implemented tracking mechanisms for fuel expenses, pensions, and Other Postretirement Benefits ("**OPEB**") related costs.

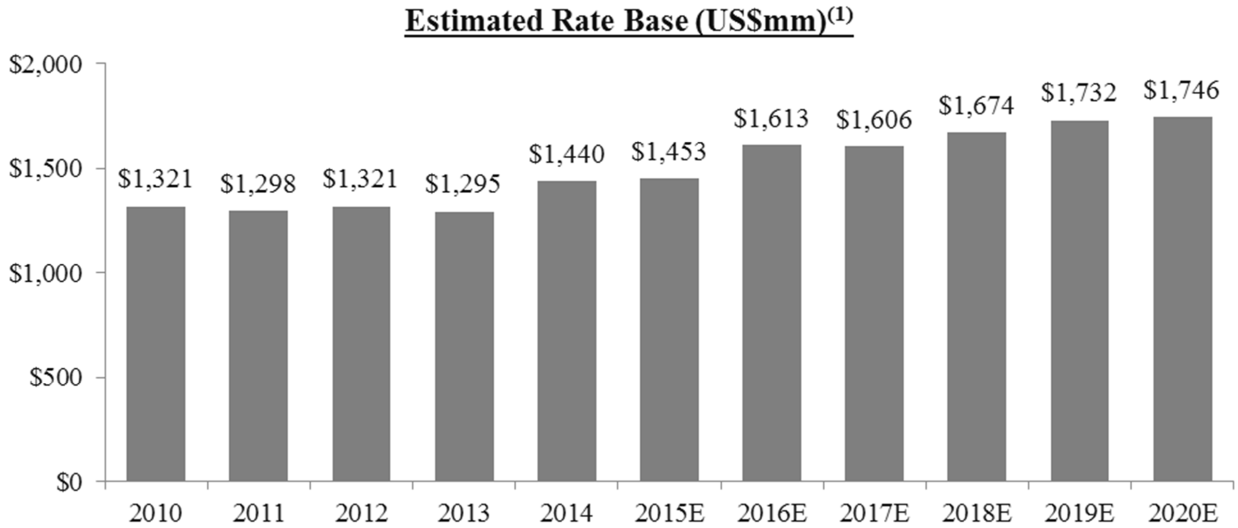
Rate Base Growth Through Capital Investment

In the period from January 1, 2010 to December 31, 2014, Empire invested US$738 million in capital investment projects, resulting in an increase of approximately US$288 million to net plant in service. This growth was driven by Empire's continued investment in its utility business to comply with environmental mandates, support customer growth, and upgrade system reliability and facilities. As at September 30, 2015, Empire forecasted capital spending from its regulated subsidiaries to be approximately US$690 million, including retirement expenditures, during the period from January 1, 2016 to December 31, 2020. Partly as a result of these expenditures, Empire's rate base is forecast to reach US$1.75 billion by December 31, 2020.



Notes:

(1) Includes estimated retirement expenditures.



Notes:

(1) Rate base approximates net plant less capital work in progress and deferred taxes.

In addition to the forecast capital spending, the Corporation's management believes there is an opportunity to leverage Algonquin's entrepreneurial track record and expertise in developing renewable power projects to allow Empire to participate in the shift in generation from high carbon sources to low carbon sources that is expected as a result of the U.S. Government's Clean Power Plan or similar federal or state initiatives. In 2014, approximately 31% of Empire's electricity generation was from coal-fired generation facilities, all of which were environmentally compliant. In the long term, Algonquin expects that there will continue to be reductions in coal-fired electrical generation and that energy will increasingly be generated by a combination of additional gas-fired and renewable power generation. Given its experience in this field, Algonquin expects to be an active participant in any future renewable power generation. Such participation could involve the combined company self-delivering new power generation capacity additions of natural gas, solar, wind, and other renewable generation which are expected to be rate base eligible investments.

Experienced Management Team

Algonquin believes that Empire and Algonquin have complementary management teams and corporate cultures focused on safety, customer service and long-term value creation that will support a smooth combination of the two companies.

Empire is a well-run utility that has an experienced management team, with its senior officers averaging nearly 20 years of experience with Empire. The management team has demonstrated leadership through the operation of a large, well-run diversified utility company providing safe, reliable and cost-effective electric, gas and water service to its customers. Algonquin believes that its existing Missouri utility operations can benefit from and be managed by this experienced Empire management team.

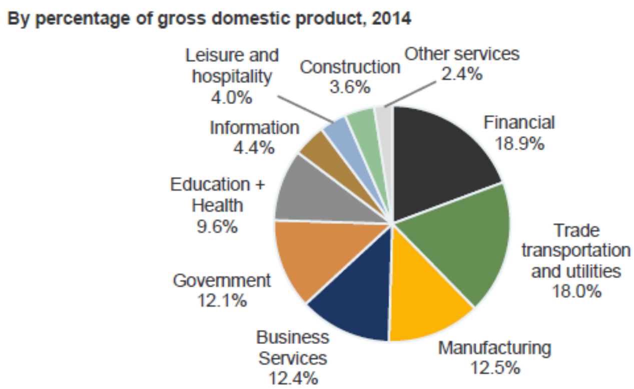
Empire's accomplished management team will fortify the leadership of its central-U.S. utility operations and provide an opportunity to consolidate these regional operations under Empire's senior management. Regional expertise in operations and project development is an asset that Algonquin believes can be leveraged to pursue potential project partnerships and future acquisition opportunities outside the jurisdictions in which Empire and Algonquin currently operate.

Empire's management team has a demonstrated track record of working productively with regulators and policy makers to obtain successful regulatory outcomes for all stakeholders. Algonquin believes that Empire's management has also fostered strong relationships with its employees, resulting in a low employee turnover, ability to recruit strong employees and few labour relations issues.

Favourable Missouri Economic Indicators

Empire's operations are located predominately in Missouri; approximately 91% of its retail revenues come from the state. As the global economy remains uncertain, the U.S. as a market remains attractive with relatively low risk and relatively positive economic outlook compared to alternative markets. Missouri is experiencing a corresponding economic improvement, with a number of economic indicators trending in a positive direction.

Missouri is well-positioned within the larger U.S. economy as a regional hub for financial, medical, education, transportation, manufacturing and retail developments. The following chart shows Missouri's key industries by percentage of GDP in 2014.



Notes:

(1) Source: 2015 Missouri Economic Report, Missouri Department of Economic Development

Missouri also possesses a growing working population, as its total labour force increased by approximately 50,000 workers between 2011 and 2015. Missouri's unemployment rate has also decreased significantly in the last several years, consistent with the U.S. national trend, from approximately 9.8% in January of 2010 to 5.8% in May of 2015 according to a report by the Missouri Department of Economic Development. The same report shows real personal income in the state has grown over the last decade, also tracking the national trend.

FINANCING THE ACQUISITION

The cash purchase price of the Acquisition and the Acquisition-Related Expenses will be financed at the closing of the Acquisition with a combination of some or all of the following: (i) net proceeds of the first instalment under the Offering; (ii) net proceeds of any subsequent bond or other debt offerings; (iii) amounts drawn under the Acquisition Credit Facilities and the existing revolving credit facilities in favour of Algonquin (the "**Revolving Facilities**"); and, (iv) existing cash on hand and other sources available to the Corporation.

Prior to the closing of the Acquisition, Algonquin (on a consolidated basis) intends to invest in short term interest bearing securities with an investment grade counterparty or reduce amounts outstanding on the Revolving Facilities with the net proceeds of the first instalment under the Offering, which are expected to be $313,000,000 (assuming no exercise of the Over-Allotment Option). In the event Algonquin reduces amounts outstanding on the Revolving Facilities, Algonquin will maintain readily available capacity under the Revolving Facilities, or have cash on hand together with such available capacity, in an amount at least equal to the net proceeds of the first instalment paid on the closing of the Offering (and the exercise of the Over-Allotment Option, if applicable). Upon the closing of the Acquisition, Algonquin (on a consolidated basis) intends to use the net proceeds of the final instalment under the Offering, which are expected to be $647,000,000 (assuming no exercise of the Over-Allotment Option), to reduce amounts outstanding under the Acquisition Credit Facilities concurrently with or following the closing of the Acquisition.

Algonquin expects that with the Offering, the Corporation will have substantially fulfilled its common equity requirement for the closing of the Acquisition (provided the Over-Allotment Option is exercised in full). With respect to any preferred equity and bond or other debt offerings, which may occur prior to or following closing of the Acquisition, Algonquin currently intends to focus on preferred equity and bond or other debt financings, denominated principally in U.S. dollars in order to provide a significant natural currency hedge.

Algonquin's overall financing plan in respect of the Acquisition is structured and targeted to maintain Algonquin's and Empire's current credit ratings profile.

See "Risk Factors" for a discussion of certain risks relating to the financing of the Acquisition.

Acquisition Credit Facilities

For purposes of financing the cash purchase price of the Acquisition, on February 9, 2016, Algonquin obtained commitment letters from Canadian Imperial Bank of Commerce, The Bank of Nova Scotia, JP Morgan Chase Bank, N.A., and Wells Fargo Bank, National Association, respectively, providing for non-revolving unsecured term credit facilities in favour of Algonquin in an aggregate amount of US$1.6 billion (the "**Acquisition Credit Facilities**"). The Acquisition Credit Facilities consist of (i) a senior unsecured bridge facility in an aggregate principal amount of up to US$535 million, repayable in full on the first anniversary following its advance, and a (ii) senior unsecured bridge facility in an aggregate principal amount of up to US$1.065 billion, repayable in full on the first anniversary following its advance.

Subject to certain prescribed exceptions, Algonquin is required to effect reductions or make prepayments of the Acquisition Credit Facilities in an amount equal to the net cash proceeds from the issuance of any indebtedness, common equity, or any other equity (including hybrid equity securities), or from any non-ordinary course asset sales or dispositions, in each case by Algonquin or any of its subsidiaries, subject to certain prescribed exceptions and certain other prescribed transactions. Net proceeds from any such offerings, including the net proceeds of the final instalment under the Offering, or from any such issuances or non-ordinary course asset sales or dispositions, will be applied to permanently reduce the commitments of the lenders under the Acquisition Credit Facilities or to repay the Acquisition Credit Facilities after they are drawn.

See "Financing the Acquisition".

THE OFFERING

Issuer:	Algonquin Power & Utilities Corp.
Selling Debentureholder:	Liberty Utilities (Canada) Corp., a direct wholly-owned subsidiary of the Corporation. See "Details of the Offering – The Selling Debentureholder".
Offering:	5.00% convertible unsecured subordinated debentures, due March 31, 2026, represented by Instalment Receipts and convertible into Common Shares at a Conversion Price of $10.60 per Common Share.
Amount:	$1,000,000,000 ($1,150,000,000 if the Over-Allotment Option is exercised in full) payable on an instalment basis.
Price:	$1,000 per Debenture represented by an Instalment Receipt, of which the first instalment of $333 is payable on the Closing Date and the final instalment of $667 is payable on or before the Final Instalment Date.
Closing Date:	On or about March 1, 2016, or such other date as may be agreed upon by the Corporation, the Selling Debentureholder and the Underwriters, but not later than March 10, 2016.
Over-Allotment Option:	The Underwriters shall have the option, exercisable in whole or in part at any time on or prior to the 30th day following the Closing Date to purchase additional Debentures represented by Instalment Receipts equal to up to 15% of the aggregate principal amount of Debentures represented by Instalment Receipts issued at the Closing Date to cover over-allotments, if any, and for market stabilization purposes. See "Plan of Distribution".
Use of Proceeds:	The net proceeds from the Offering (including both the first instalment and final instalment) will be, in the aggregate, $958,400,000 determined after deducting the Underwriters' fee and the estimated expenses of the Offering. In the event that the Over-Allotment Option is exercised in full, the net proceeds will be, in the aggregate, $1,102,400,000. Prior to the closing of the Acquisition, the net proceeds of the first instalment, expected to be $313,000,000 will initially be used to (a) reduce amounts outstanding on the Revolving Facilities or (b) invest in short-term interest bearing securities with investment grade counterparties. In the event the net proceeds of the first instalment are used to reduce outstanding indebtedness, Algonquin will maintain readily available capacity under the Revolving Facilities, or have cash on hand together with such available capacity, in an amount at least equal to the net proceeds of the first instalment paid on the closing of the Offering (and the exercise of the Over-Allotment Option, if applicable). The net proceeds of the final instalment from the Offering are expected to be $647,000,000 (assuming no exercise of the Offering's Over-Allotment Option), and will be used, together with the net proceeds of the first instalment, to finance, directly or indirectly, part of the purchase price payable for the Acquisition and for other Acquisition-Related Expenses. See "Use of Proceeds".
Listing:	Algonquin has applied to list the Instalment Receipts (representing the Debentures) and the Common Shares to be issued upon conversion or maturity of the Debentures on the TSX. **The Debentures will not be listed.** The Common Shares are currently listed on the TSX under the symbol "AQN".

Interest:	Annual rate of 5.00% per $1,000 principal amount of Debentures will be payable quarterly in arrears in equal instalments on the 15th day of March, June, September and December of each year (or the next business day if the 15th falls on a weekend or holiday) to and including the Final Instalment Date. The first interest payment will be made on June 15, 2016 in the amount of $14.5205 per $1,000 principal amount of Debentures and will include interest payable from and including the Closing Date. Subsequently, quarterly interest payments will be made in the amount of $12.50 per $1,000 principal amount of Debentures. Based on a first instalment of $333 per $1,000 principal amount of Debentures, the effective yield per annum to and including the Final Instalment Date is 15.0%. If the Final Instalment Date is prior to the first anniversary of the Closing Date, holders of Debentures who have paid the final instalment on or before the Final Instalment Date will be entitled to receive, on the business day following the Final Instalment Date, in addition to the payment of accrued and unpaid interest to and including the Final Instalment Date, an amount equal to the interest that would have accrued from the day following the Final Instalment Date to and including the first anniversary of the Closing Date had the Debentures remained outstanding and continued to accrue interest until and including such date (which is referred to in this Prospectus as the "**Make-Whole Payment**"). No Make-Whole Payment will be payable if the Final Instalment Date occurs on or after the first anniversary of the Closing Date. No interest shall accrue on any Debentures following the Final Instalment Date. See "Details of the Offering – Debentures".
Conversion:	At the option of the holder and provided that payment of the final instalment has been made, each Debenture will be convertible into Common Shares at any time on or after the Final Instalment Date, but prior to the earlier of the date that the Corporation redeems the Debentures or the Maturity Date. The Conversion Price will be $10.60 per Common Share, being a conversion rate of 94.3396 Common Shares per $1,000 principal amount of Debentures, subject to adjustment in certain events. A holder of Debentures who does not exercise its conversion privilege concurrently with the payment of the final instalment no later than the Final Instalment Date will hold a Debenture that pays 0% interest and may be redeemed by the Corporation in whole or in part on any trading day following the Final Instalment Date at a price equal to its principal amount plus any unpaid interest which accrued prior to and including the Final Instalment Date. No fractional Common Shares will be issued on any conversion, but in lieu thereof, the Corporation will satisfy such fractional interest by a cash payment equal to the fractional interest multiplied by the Conversion Price provided, however, the Corporation shall not be required to make any payment greater than $10.00. See "Details of the Offering – Debentures – Conversion Right".

Instalment Payment Arrangements:	The price of $1,000 per $1,000 principal amount of Debentures is payable on an instalment basis. Prior to full payment, beneficial ownership of the Debentures will be represented by Instalment Receipts. The first instalment of $333 per $1,000 principal amount of Debentures is payable on the Closing Date. The final instalment of $667 per $1,000 principal amount of Debentures is payable on or before the Final Instalment Date. The Final Instalment Notice will set the Final Instalment Date, which shall not be less than 15 days nor more than 90 days following the date of such notice. The Final Instalment Notice shall not be provided to holders until the Approval Conditions have been satisfied. The Final Instalment Date may occur up to 90 days following September 8, 2017. See "Details of the Offering". Each Debenture represented by an Instalment Receipt will be pledged to the Selling Debentureholder to secure the obligation of the holder of the Instalment Receipt to pay the final instalment in respect of such Debenture. **If a holder of an Instalment Receipt does not pay the final instalment on or before the Final Instalment Date, the Debentures evidenced by such Instalment Receipt may, at the option of the Selling Debentureholder, upon compliance with applicable law and the terms of the Instalment Receipt Agreement governing the Instalment Receipts, be forfeited to the Selling Debentureholder in full satisfaction of the holder's obligations or such Debentures may be sold and the holder of the Instalment Receipt shall remain liable for any deficiency if the proceeds of such sale are insufficient to cover the amount of the final instalment and the costs of such sale (such costs of sale not to exceed $25 per Debenture). See "Details of the Offering – Instalment Receipts".**
Rights of Instalment Receipt Holders:	Holders of Instalment Receipts will be entitled, in the manner set forth in the Instalment Receipt Agreement described herein, to fully receive payments of accrued interest and to exercise the rights of ownership attached to the Debentures represented by such Instalment Receipts unless they fail to pay the final instalment on or before the Final Instalment Date. See "Details of the Offering – Instalment Receipts – Rights and Privileges".
Redemption:	Prior to the Final Instalment Date, the Debentures may not be redeemed by the Corporation, except that the Debentures will be redeemed by the Corporation at a price equal to their principal amount plus accrued and unpaid interest following the earlier of: (i) notification to holders that the Approval Conditions will not be satisfied; (ii) termination of the Acquisition Agreement in accordance with its terms; and (iii) September 11, 2017 if notice of the Final Instalment Date has not been given to holders of Instalment Receipts on or before September 8, 2017. Upon any such redemption, the Corporation will pay for each Debenture: (i) $333 plus accrued and unpaid interest to the holder of the Instalment Receipt; and (ii) $667 to the Selling Debentureholder on behalf of the holder of the Instalment Receipt in satisfaction of the final instalment. Until such time as the Debentures have been redeemed or the Final Instalment Date has occurred, the Corporation will maintain readily available capacity under the Revolving Facilities, or have cash on hand together with such available capacity, in an amount at least equal to the net proceeds of the first instalment paid on the closing of the Offering (and on the closing of the Over-Allotment Option, if applicable). In addition, after the Final Instalment Date, any Debentures not converted may be redeemed by the Corporation at a price equal to their principal amount plus any unpaid interest, which accrued prior to and including the Final Instalment Date. See "Details of the Offering – Debentures – Redemption".

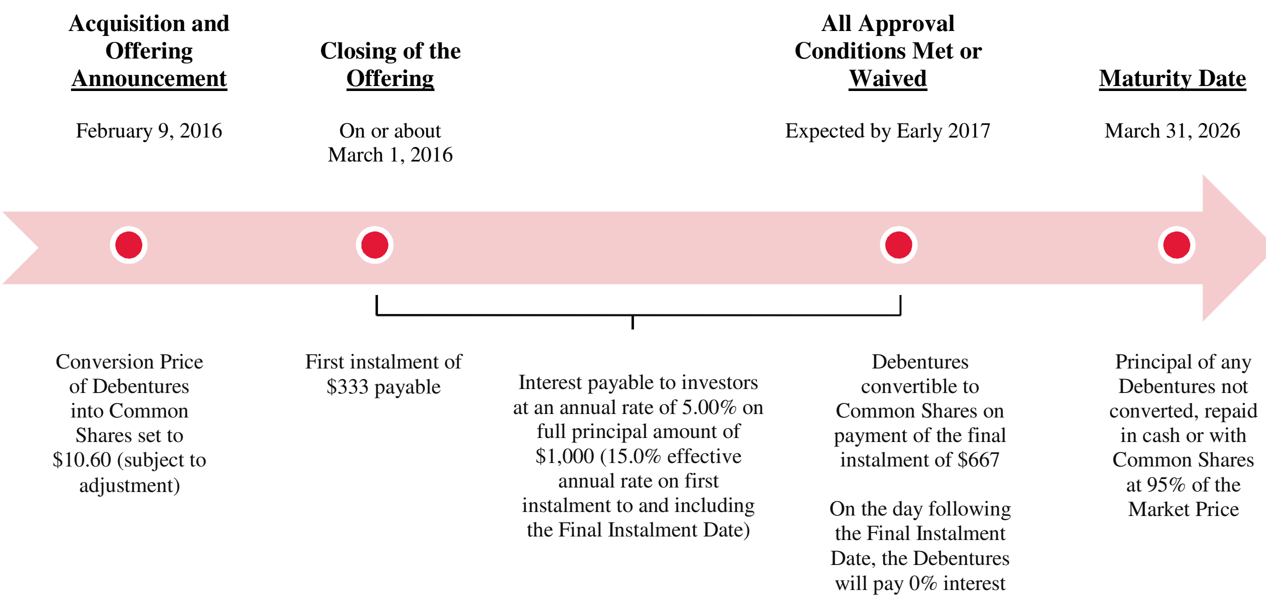
Maturity Date: March 31, 2026.

Payment upon Maturity: On the Maturity Date, the Corporation will repay the principal amount of any Debentures not converted and remaining outstanding, in cash. The Corporation may, at its option and without prior notice, satisfy the obligation to pay the principal amount of such Debentures on maturity by delivery of that number of freely tradable Common Shares obtained by dividing the aggregate principal amount of the Debentures then outstanding by 95% of the Market Price. See “Details of the Offering – Debentures – Payment Upon Maturity”.

Subordination: The Debentures will be direct unsecured obligations of Algonquin. Payment of the principal of, interest on, any Make-Whole Payments and other amounts owing in respect of each Debenture will (i) be subordinated in right of payment to all present and future Senior Indebtedness of Algonquin and (ii) rank pari passu with each other Debenture of the same series (regardless of their actual date or terms of issue) and, subject to statutory preferred exceptions, with all other present and future subordinated and unsecured indebtedness of Algonquin. The trust indenture pursuant to which the Debentures will be issued does not limit the ability of the Corporation to incur additional indebtedness, including indebtedness that ranks senior to the Debentures, or from mortgaging, pledging, charging, hypothecating, granting a security interest in or otherwise encumbering any or all of its properties to secure any indebtedness. See “Details of the Offering – Debentures – Subordination”.

Risk Factors: An investment in the Debentures represented by Instalment Receipts and the Common Shares issuable upon conversion thereof involves certain risks which should be carefully considered by prospective investors, including risks in respect of the Acquisition, the Instalment Receipts, the Debentures, the Common Shares and the post-Acquisition business and operations of the Corporation and Empire. See “Risk Factors”.

SUMMARY OF IMPORTANT DATES

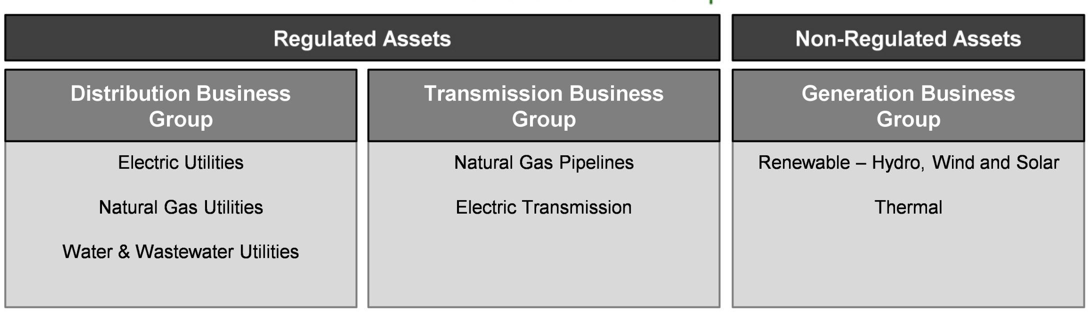


ALGONQUIN

Overview

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

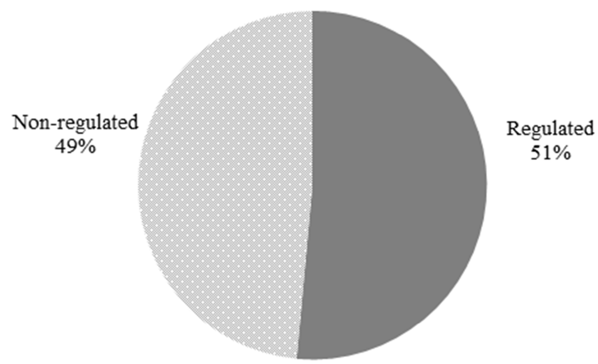
Algonquin's operations are organized across three business units consisting of Generation, Transmission and Distribution. The Generation Business Group ("**Generation Group**") owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation utility assets; the recently 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.



For the twelve months ended September 30, 2015, regulated assets contributed 51% of Algonquin's Adjusted EBITDA (as defined in this Prospectus), with non-regulated assets contributing the balance of 49%. Over the five years ended September 30, 2015, the Corporation's annual Adjusted EBITDA has grown from $97.2 million to $350.1 million.

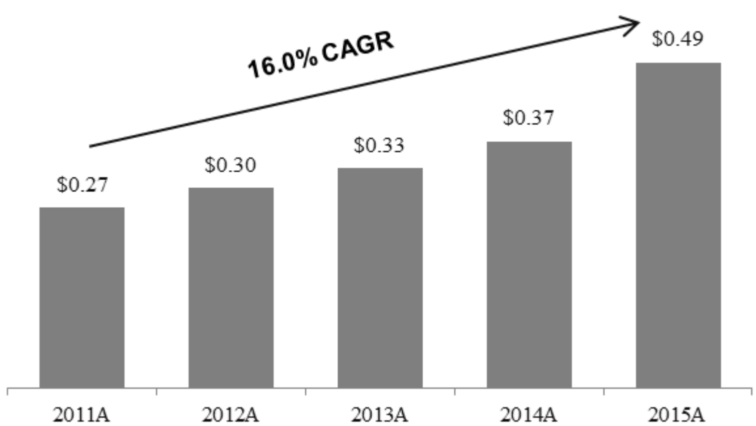
Algonquin Regulated vs Non-Regulated Adjusted EBITDA

For the twelve months ended September 30, 2015



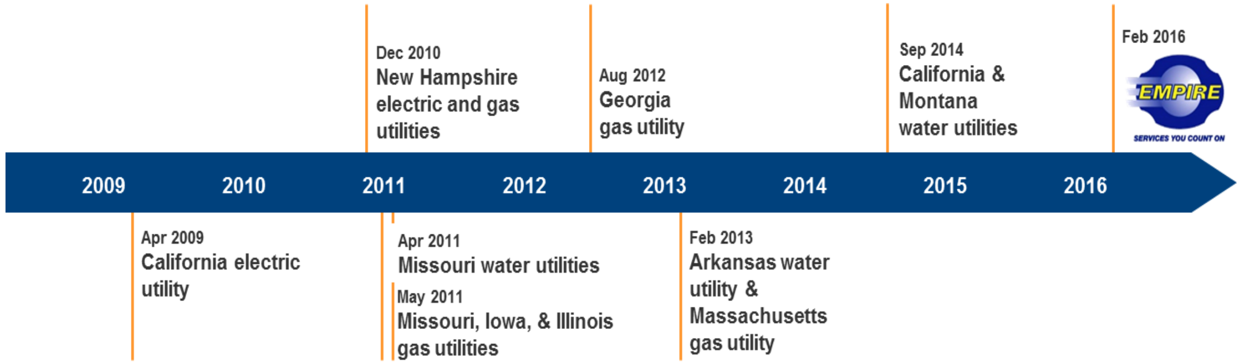
Over the five years from September 30, 2010 to September 30, 2015, Algonquin has significantly grown its revenues, Adjusted EBITDA and net income, leading to a total shareholder return of approximately 24.6% per annum. Over the same period, Algonquin has increased its annualized dividend from $0.24 to US$0.385 per Common Share. As at February 12, 2016, the US$0.385 denominated annualized dividend, when converted at the spot exchange rate of US$1.00 = $1.3835, equates to a Canadian dollar equivalent of $0.533 per Common Share.

Dividend Growth History (C$)(1)



(1) Algonquin commenced declaring dividends in US$ as of August 2014. US$ dividends are converted to Canadian dollars at the Bank of Canada noon rate on the date payable.

Algonquin has substantial experience in combining newly acquired businesses with existing operations. In part due to this experience, management believes that integration of Empire and Algonquin should be smooth, and that leveraging best practices from each entity may contribute to enhanced service for customers and ratepayers. Algonquin's recent acquisitions of electric, gas and water utilities are depicted in the timeline below.



See "Recent Developments" for further information on the Corporation's most recently completed acquisition.

Generation 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, solar and thermal facilities with a combined gross generating capacity of approximately 120 MW, 700 MW, 35 MW and 335 MW, respectively. Approximately 83% of the electrical output from the hydroelectric, wind, solar and thermal generating facilities is sold pursuant to long-term contractual arrangements, which have a weighted average remaining contract life of 13 years.

The Generation Group also has a portfolio of development projects, which are expected to be commissioned between 2016 and 2018 and will add approximately 711 MW of generation capacity from wind and solar powered generating stations with an average contract life of 20 years.

Distribution Group

The Distribution Group operates diversified rate regulated electricity, natural gas, water distribution and wastewater utilities, providing services to approximately 560,000 customers. The Distribution Group provides safe, high quality and reliable services to its ratepayers through its portfolio of utility systems in the United States and delivers stable and predictable earnings to the Corporation. In addition to encouraging and supporting organic growth within its service territories, the Distribution Group delivers continued growth in earnings through accretive acquisitions 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 customers. 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 customers. The Distribution Group's regulated water distribution and wastewater collection utility systems are located in the States of Arizona, Arkansas, California, Illinois, Missouri, Montana and Texas and together serve approximately 177,000 customers.

Transmission Group

In 2014, Algonquin 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 Corporation believes that the creation of the Transmission Group complements the growth of both the Generation and Distribution Groups.

The Transmission Group is currently participating in two related joint venture pipeline projects with Kinder Morgan, Inc. ("**Kinder Morgan**") in connection with Kinder Morgan's Northeast Energy Direct project to serve New England natural gas markets. The Transmission Group is participating with Kinder Morgan, through a newly formed entity ("**Northeast Expansion LLC**"), in the development, construction and ownership of a natural gas transmission pipeline to be located between Wright, New York and Dracut, Massachusetts (the "**Market Path Project**"). The Transmission Group has initially subscribed for a 2.5% interest in Northeast Expansion LLC. The Transmission Group expects to invest approximately $5.0 million (US$3.8 million) in the Market Path Project in 2016. As proposed, the potential investment could exceed US$300 million over a three-year period if the Transmission Group elects to increase its interest. In addition, the Transmission Group is also participating, in partnership with Kinder Morgan and through a newly formed entity (the "**Northeast Supply Pipeline LLC**"), in the development of a gas pipeline traversing New York State, between Wright, New York and northeast Pennsylvania (the "**Supply Path Project**"). The Transmission Group has initially subscribed for a 4.0% interest in the Supply Path Project, with total capital investment potential estimated to be up to US$200 million over the next three years if the Transmission Group elects to increase its interest. Subject to certain prescribed conditions, Algonquin may elect to increase its participation levels by up to 10% in each project.

See the section entitled "Description of the Business" in the AIF for further details relating to the Corporation's business.

RECENT DEVELOPMENTS

Credit Rating Reviews

On February 10, 2016, DBRS Limited ("**DBRS**") placed Algonquin's 'BBB (low)' Issuer Rating and 'Pfd-3 (low)' Preferred Shares ratings 'Under Review with Developing Implications'. DBRS also placed the 'BBB (high)' Issuer Rating, 'BBB (high)' Series A, Series C, and Series D Senior Notes ratings of Liberty Utilities Finance GP1 ("**LUF**", a special purpose financing entity of Liberty Utilities) and the 'BBB (low)' Issuer Rating and 'BBB (low)' Senior Unsecured Debentures ratings of Algonquin Power Co. ("**APCo**") 'Under Review with Developing Implications'.

For Algonquin, Liberty Utilities and LUF, the ratings actions reflect DBRS's view that the Acquisition will have a relatively neutral impact on the business risk assessments of each of Algonquin, Liberty Utilities and LUF, and that the impact on the financial risk assessment was at the time of the ratings actions uncertain since the financing plan had not been finalized. For APCo, the DBRS announcement states that the credit quality of APCo could be indirectly affected should Algonquin's credit profile significantly deteriorate following the Acquisition. This reflects DBRS's view that APCo relies partly on Algonquin to provide equity injections to maintain key financial metrics within the rating category and that if Algonquin's debt levels increase significantly following the Acquisition, the Corporation may require more dividends from APCo to service its debt. DBRS indicated that it will review the finalized financing plan and further review any potential impact of the Acquisition on each entity's credit profile.

On February 9, 2016, S&P revised its outlook on Algonquin, APCo and Liberty Utilities to negative from stable, while affirming the existing ratings for each of such companies, including the 'BBB' long-term corporate rating on Algonquin. S&P indicated that the negative outlook reflects the execution risk associated with the Acquisition and the potential for lower ratings stemming from the limited ability to absorb weaker financial performance. The revised outlook also reflects S&P's expectation that certain of Algonquin's consolidated pro forma credit metrics will materially weaken due to the Offering (S&P treats the Debentures represented by Instalment Receipts as debt until they are converted into Common Shares).

On February 10, 2016, S&P affirmed its 'BBB' issuer credit rating on Empire while revising the outlook to negative from developing. The negative outlook reflects the potential for lower ratings on Empire driven by the expectation of materially weaker credit measures at the combined enterprise following the Acquisition, while S&P's rating on Empire is based on the company's strong business and significant financial risk profiles.

On February 10, 2016, Moody's issued a release stating the Acquisition had no immediate rating impact on Empire and affirmed its 'Baa1' senior unsecured rating.

Acquisition of Park Water

On January 11, 2016, Algonquin announced that Liberty Utilities closed a previously announced agreement with Western Water Holdings, a wholly-owned investment of Carlyle Infrastructure, to acquire the regulated water distribution utility, Park Water Company, now known as Liberty Utilities (Park Water) Corp. ("**Park Water**"). Total consideration for the utility purchase was $436.4 million (US$327 million), which includes the assumption of approximately $103 million (US$77 million) of existing long-term utility debt. The acquisition was partially financed by drawing the full amount on a $313.6 million (US$235.0 million) term credit facility with two U.S. banks.

Park Water owns and operates three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in Southern California and Western Montana. Park Water provides, owns and operates the water system in central Los Angeles. Apple Valley Ranchos Water Company, now known as Liberty Utilities (Apple Valley Ranchos Water) Corp. ("**Apple Valley**"), owns and operates the water system in Apple Valley, California. Mountain Water Company ("**Mountain Water**") owns and operates the water system serving the municipality of Missoula, Montana. Mountain Water and Apple Valley are wholly-owned by Park Water. The three utilities collectively serve approximately 74,000 customer connections and have more than 1,000 miles of distribution mains.

Offering of Common Shares

On December 2, 2015, Algonquin completed an offering of 14,355,000 Common Shares at a price of $10.45 per Common Share for gross proceeds of approximately $150 million. The offering was completed under a prospectus supplement to the Corporation's short form base shelf prospectus dated February 18, 2014.

Empire Fourth Quarter Results

On February 4, 2016, Empire issued a press release announcing its earnings for the fourth quarter of 2015 and for the twelve month period ended December 31, 2015. Empire reported consolidated earnings for the year ended December 31, 2015 of US$56.6 million, or US$1.30 per share (US$1.29 on a diluted basis) compared to 2014 earnings of US$67.1 million, or US$1.55 (basic and diluted) per share. Earnings for the 2015 fourth quarter were US$9.9 million, or US$0.23 per share (basic and diluted), compared with 2014 fourth quarter earnings of US$11.1 million, or US$0.26 per share (basic and diluted).

Empire noted that the "mildest fourth quarter weather in 30 years drove a decrease in fourth quarter earnings, off-setting the positive margin impact from new Missouri rates, which became effective July 26, 2015. " Electric segment sales declined 6.3% quarter over quarter. Higher depreciation and interest expense also negatively impacted the quarter.

Earnings for the full year 2015 were also negatively impacted by the mild fourth quarter weather. Year over year electric segment sales were 1.8% lower in 2015. In addition, earnings were also lower due to the effects of higher costs related to the Asbury Air Quality Control System ("**AQCS**") environmental upgrade that went into service December 15, 2014, which were not captured in electric rates until the new Missouri rates took effect on July 26, 2015.

Empire's audited financials for the year ended December 31, 2015 have not yet been released. The preliminary financial data included in this Prospectus was derived from publicly available information about Empire that was prepared by, and was the responsibility of, Empire's management. PricewaterhouseCoopers LLP, Empire's auditors, have not audited, reviewed, compiled or performed any procedures with respect to the accompanying preliminary financial data. Accordingly, PricewaterhouseCoopers LLP does not express an opinion or any other form of assurance with respect thereto. Empire's 2015 audited financial results may differ from the preliminary financial information in its press release summarized above.

THE ACQUISITION

Acquisition Overview

On February 9, 2016, AcquisitionCo and Merger Sub entered into the Acquisition Agreement with Empire which provides for, among other things, the acquisition by AcquisitionCo of Empire through the Merger (as defined in this Prospectus). The aggregate purchase price for the Acquisition is approximately US$2.4 billion, comprised of approximately US$1.5 billion in cash payable on closing and the assumption of approximately US$0.9 billion of debt. The Acquisition is subject to receipt of Empire Shareholder Approval (at its shareholder meeting expected to occur in the second or third quarter of 2016) and certain regulatory and governmental approvals, including the expiration or termination of any applicable waiting period under the HSR Act, CFIUS Approval, the approval by each of FERC, the FCC and the State Commissions, and the satisfaction of other customary closing conditions. The closing of the Acquisition is currently expected to occur in the first quarter of 2017.

Based on pro forma financial information as at September 30, 2015, following the Acquisition, Algonquin's total assets will increase from approximately $4.8 billion to approximately $8.9 billion and the percentage of its Adjusted EBITDA that is regulated Adjusted EBITDA is expected to increase from approximately 51% to approximately 72%. Following the Acquisition, the regulated utility subsidiaries of Algonquin will serve approximately 778,000 customers.

Algonquin's approach to operating its regulated utilities is to build a strong local presence in each market resulting in a strong local customer service presence, including local call centres and walk-in store fronts. Algonquin also engages locally with the regulators in each of its regulatory jurisdictions creating strong, mutually constructive regulatory relationships that benefit all stakeholders, including creating value for customers and investment in local communities in which its utilities operate.

With respect to Empire's operations, Algonquin intends to maintain Empire's existing local presence, including existing service centres, call contact centres, customer service offices and local business and community representatives. Algonquin will continue to invest in local communities, including maintaining Empire's existing headquarters location in Joplin, Missouri. Algonquin also expects to retain Empire's existing management team, allowing local managers to continue being responsive to employees, customers and regulators and contributing to a smooth transition to Algonquin ownership which is seamless to customers and regulators.

Empire Overview

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, with approximately 218,000 customers in Missouri, Kansas, Oklahoma, and Arkansas. Empire, a Kansas corporation organized in 1909, is an operating public utility with its common stock listed on the NYSE under the ticker symbol "EDE".

The vertically-integrated regulated electricity operations of Empire represent the majority of its operating revenues and assets. For the year ended December 31, 2014, approximately 91% of Empire's revenues were attributable to its electricity operations, with approximately 8% of revenues attributable to its natural gas subsidiary, and approximately 1% attributable to its fiber optics business.

Empire's electric operations cover a service territory of approximately 10,000 square miles, located principally in southwestern Missouri, and also include smaller areas in southeastern Kansas, northeastern Oklahoma and northwestern Arkansas. Empire supplies electric service to customers in 119 incorporated communities and to various unincorporated areas and at wholesale to four municipally-owned distribution systems. The largest urban area served is the city of Joplin, Missouri, and its immediate vicinity, with a population of approximately 160,000. As of December 31, 2014, Empire's electric operations served approximately 170,000 customers.

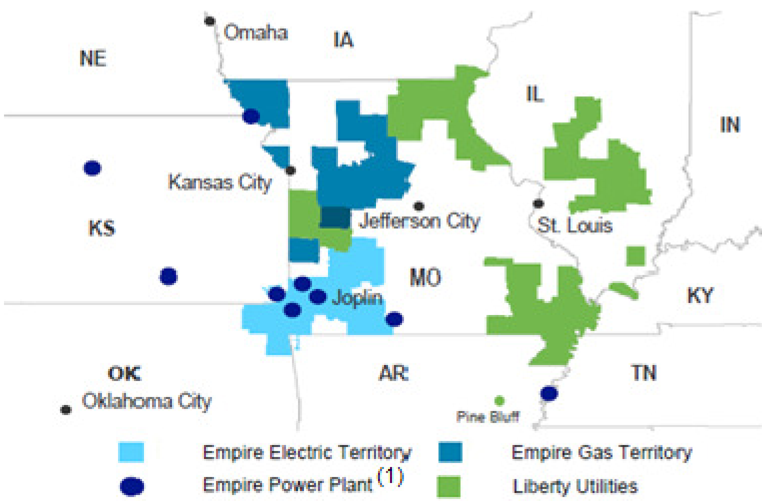
In its electric service territories, Empire operates under franchise agreements having original terms of a minimum of 20 years in virtually all of the incorporated communities. Approximately 55% of the electric operating revenues in 2014 were derived from incorporated communities with franchises having at least 10 years remaining and approximately 15% were derived from incorporated communities in which the franchises have remaining terms of 10 years or less. Although the franchise agreements contain no renewal provisions, in recent years, Empire has obtained renewals of all expiring electric franchises prior to the expiration dates.

Empire's gas operations serve customers in northwest, north central and west central Missouri. As of December 31, 2014, the gas operations served approximately 43,500 customers. Empire provided natural gas distribution to 48 communities and 422 transportation customers as of December 31, 2014. The largest urban area served by Empire's gas operations is the city of Sedalia with a population of over 20,000. Empire operates under gas franchises having original terms of 20 years in virtually all of the incorporated communities. As of December 31, 2014, 18 of the gas franchises had 10 years or more remaining on their respective terms and 26 of the gas franchises had less than 10 years remaining on their respective terms. Although the franchise agreements contain no renewal provisions, Empire has obtained renewals of all expiring gas franchises prior to the expiration dates.

Empire's other segment consists of a fiber optics business. As of December 31, 2014, Empire's fiber optics business served 121 customers.

Empire's operating revenue in fiscal 2014 totalled approximately US$652 million and for the nine-month period ended September 30, 2015, totalled approximately US$469 million. As of September 30, 2015, Empire had total assets of approximately US$2.5 billion. Empire operates its businesses as three segments: electric, gas and other (consisting of its fiber optics business). Empire's gross operating revenues in 2014 were derived as follows: 90.8% from electric segment sales (including 0.3% from the sale of water); 8.0% of from gas segment sales; and 1.2% from its other segment sales.

The following map depicts the service territories and generating operations of Empire and its regulated utility subsidiaries, as well as the regional operations of Algonquin's regulated distribution business which operates through Liberty Utilities and its subsidiaries.



(1) Empire has PPAs (as defined in this Prospectus) in place in respect of two windfarms located in Kansas (depicted in the map above). Empire does not have an ownership interest in either windfarm.

Acquisition Highlights

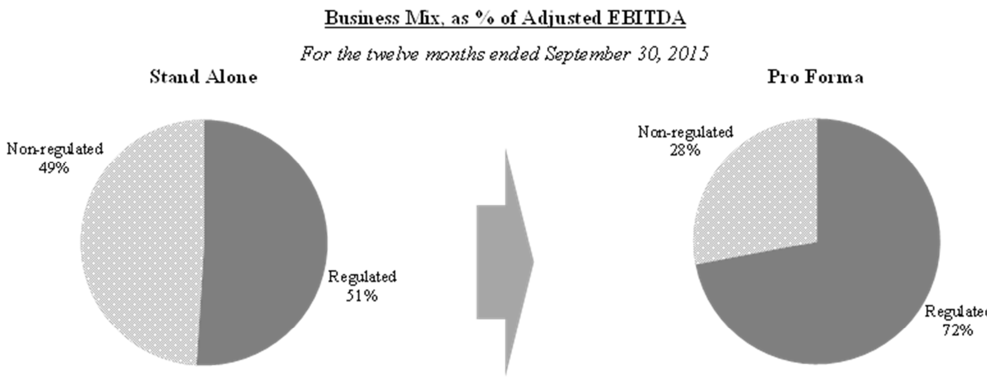
Accretive to Earnings and Adjusted Funds from Operations per Common Share

Management expects the Acquisition will be accretive to Algonquin's earnings per Common Share in the first full year following closing of the Acquisition. Management estimates the Acquisition to be approximately 7% - 9% accretive to Algonquin's earnings per Common Share over a three-year period following completion of the acquisition, excluding one-time Acquisition-Related Expenses, and assuming a stable currency exchange environment. Management also expects that the Acquisition will be approximately 12% - 14% accretive to Algonquin's Adjusted Funds from Operations per Common Share in the first full year following closing of the

Acquisition, excluding one-time Acquisition-Related Expenses, and assuming a stable currency exchange environment. Such material accretion is forecast to remain robust notwithstanding a scenario in which the Canadian dollar strengthens. Management expects the Acquisition to provide additional support for Algonquin's 10% annual dividend growth target through 2019.

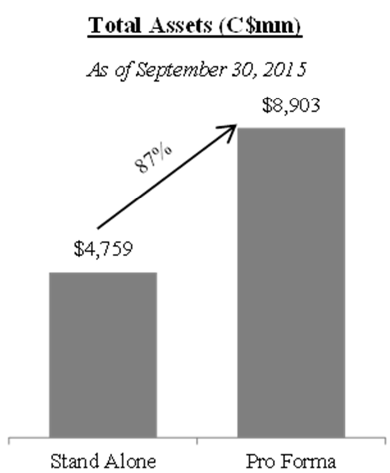
Shift in Business Mix towards Regulated Operations

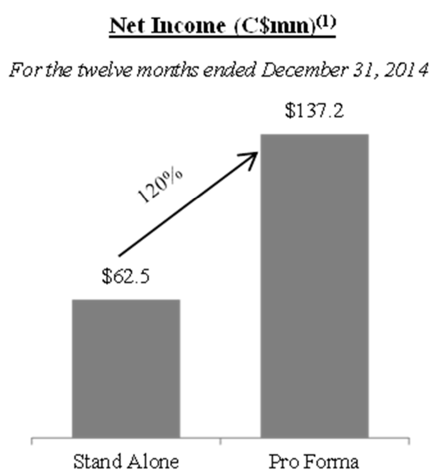
The Acquisition represents an opportunity to increase the contribution of regulated utility operations to Algonquin. As a result of the Acquisition, regulated utility operations will represent 72% of Adjusted EBITDA from 51% on a stand-alone basis for the period ending September 30, 2015. Management anticipates that the increased contribution from regulated operations will enhance Algonquin's stability and predictability of Adjusted EBITDA and net income and increase the overall quality of cash flows. This shift in business mix as a percentage of Adjusted EBITDA is shown below.



Increased Operating Scale

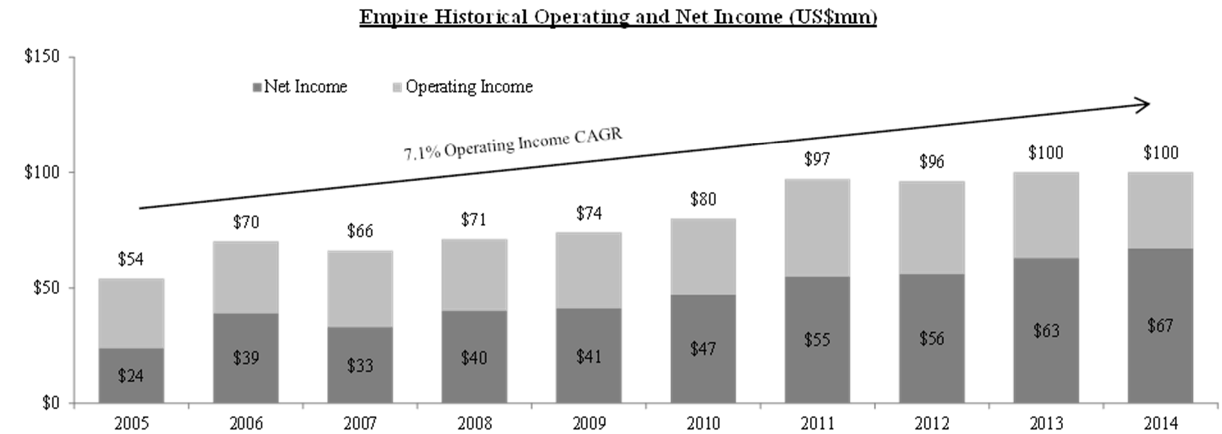
As a result of the Acquisition, Algonquin's enterprise value will increase by approximately 78%. Post-Acquisition, on a pro forma basis as at September 30, 2015 total assets will increase from approximately \$4.8 billion to approximately \$8.9 billion and net income for the twelve months ended December 31, 2014 will increase from approximately \$62.5 million to \$137.2 million. Management believes that the Acquisition will enhance Algonquin's access to equity and debt capital markets and economies of scale, which is expected to improve the terms upon which the Corporation will fund its future growth projects. The following charts illustrate Algonquin's total assets and net income on a stand-alone and pro forma basis, as at September 30, 2015 and for the twelve months ended December 31, 2014, respectively, to reflect the increased scale resulting from completion of the Acquisition.

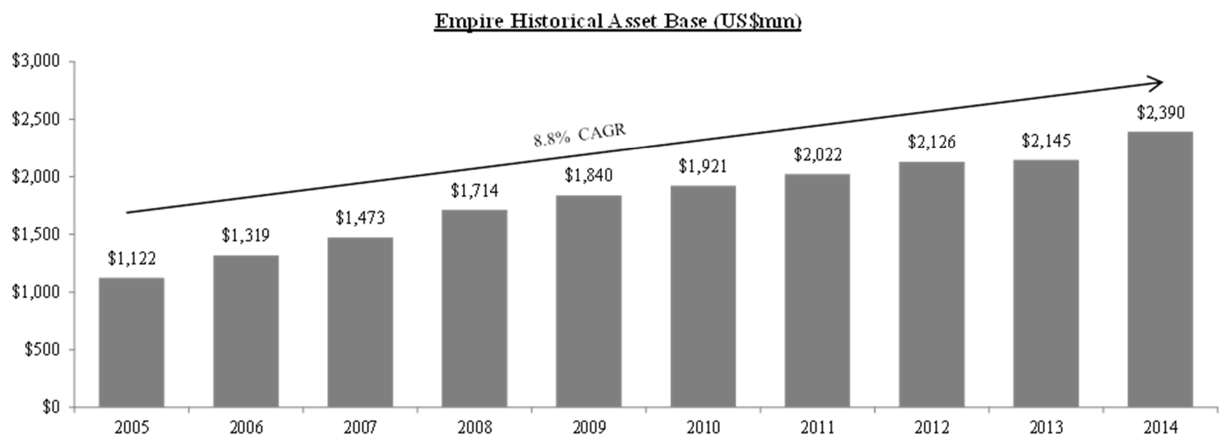




(1) Net earnings attributable to Algonquin.

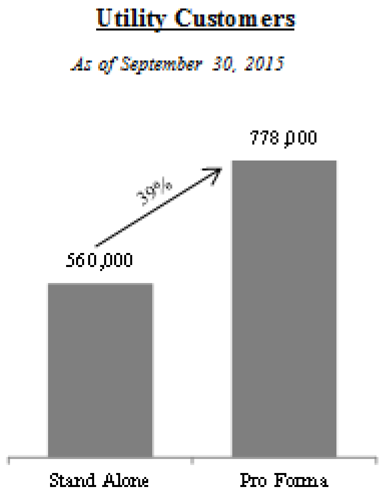
Management expects the Acquisition to produce attractive, predictable earnings growth as a result of the expanded asset base. From 2005 to 2014 Empire achieved a strong CAGR (as defined in this Prospectus) of its operating and net income and asset base, as illustrated in the charts below.

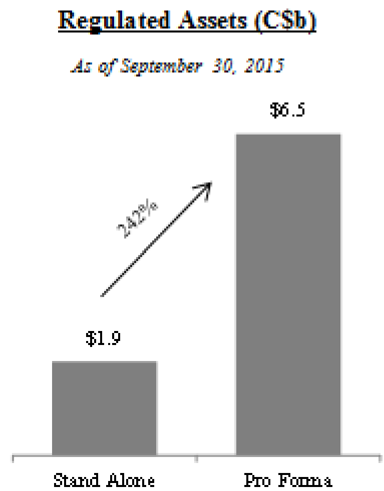




Diversification of Regulated Operations

The Acquisition adds a large profitable regulated distribution and generation business, increasing the Corporation's scale, diversity of customers and geographies of service. Following the Acquisition, Algonquin's regulated operations will have pro forma total assets of $6.5 billion, will operate regulated utilities across thirteen U.S. states and serve approximately 778,000 utility customers, representing an increase of $3.3 billion, two U.S. states and 218,000 utility customers.





Consistent with the Corporation's diversification and growth strategy, its operations will be further diversified across existing and new regulatory jurisdictions and geographies of Missouri, Arkansas, Kansas and Oklahoma. The Acquisition will result in balanced diversified regulated operations across electric, natural gas and water/wastewater utilities.

Constructive Regulatory Jurisdictions

Nearly all of Empire's regulated utility operations are in regulatory jurisdictions familiar to Algonquin from its existing regulated utility operations. For the year ended December 31, 2014, approximately 91% of Empire's retail revenues came from Missouri where Empire has an established and constructive regulatory relationship with the MPSC. Empire successfully obtained MPSC approval to acquire its regulated natural gas utility in 2006 and it has had successful rate case outcomes, including the use of various trackers for some operations and maintenance cost, as well as pension and retiree healthcare obligations all of which has served to reduce regulatory lag. Furthermore, the Missouri legislature has recently discussed the *21st Century Grid Modernization and Stabilization Act*, a utility industry supported legislative initiative which, if implemented, would be expected to further reduce regulatory lag.

All of Empire's jurisdictions have a fuel recovery mechanism, whereby any changes in fuel and purchased power expense are passed through to customers.

Missouri also provides for an Infrastructure System Replacement Surcharge for gas utilities which allows for the immediate recovery of costs related to the replacement of gas distribution system infrastructure without requiring a rate case. At present, Missouri legislators have introduced a proposed bill which would create a PBR regulatory construct for electric utilities in Missouri. Under a PBR, the electric utilities could have the potential to seek annual rate adjustments for invested capital and inflationary increases.

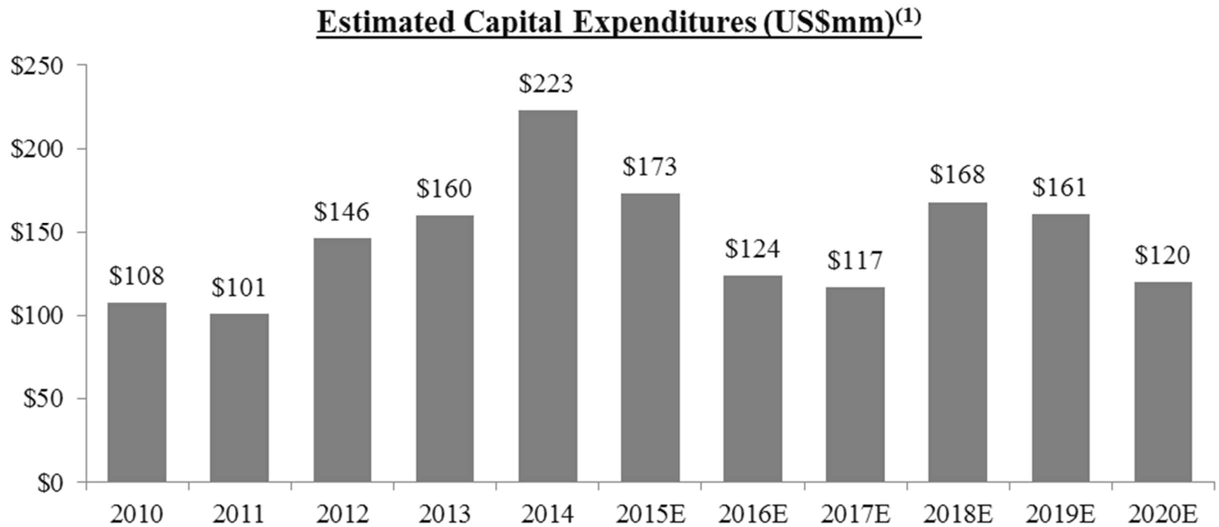
A recent statute was passed in Oklahoma which allows multi-jurisdictional companies such as Empire, who serve less than 10% of total customers within the State of Oklahoma, to benefit from rate reciprocity such that Empire is able to charge its Missouri rates to its customer base in Oklahoma, subject to regulatory approval.

Similar to Missouri, Arkansas has recently enacted legislation which allows utilities to seek PBR structures and apply for annual rate increases to reflect increased investments and inflation.

In Kansas, Empire has maintained constructive regulatory relationships and has implemented tracking mechanisms for fuel expenses, pensions, and OPEBs related costs.

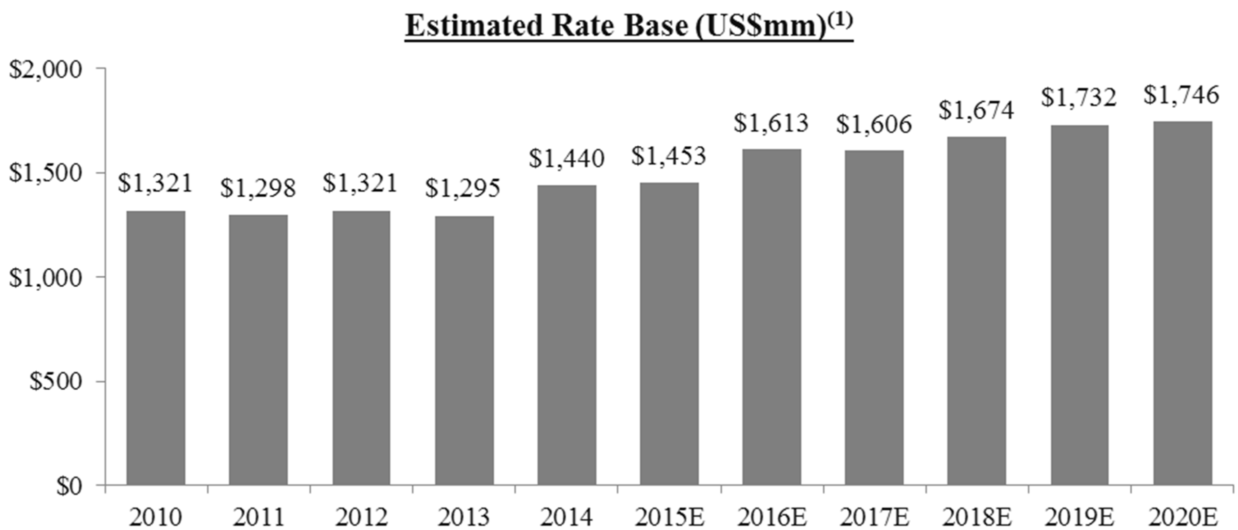
Rate Base Growth Through Capital Investment

In the period from January 1, 2010 to December 31, 2014, Empire invested US$738 million in capital investment projects, resulting in an increase of approximately US$288 million to net plant in service. This growth was driven by Empire's continued investment in its utility business to comply with environmental mandates, support customer growth, and upgrade system reliability and facilities. As at September 30, 2015, Empire forecasted capital spending from its regulated subsidiaries to be approximately US$690 million, including retirement expenditures, during the period from January 1, 2016 to December 31, 2020. Partly as a result of these expenditures, Empire's rate base is forecast to reach US$1.75 billion by December 31, 2020.



Notes:

(1) Includes estimated retirement expenditures.



Notes:

(1) Rate base approximates net plant less capital work in progress and deferred taxes.

In addition to the forecast capital spending, the Corporation's management believes there is an opportunity to leverage Algonquin's entrepreneurial track record and expertise in developing renewable power projects to allow

Empire to participate in the shift in generation from high carbon sources to low carbon sources that is expected as a result of the U.S. Government's Clean Power Plan or similar federal or state initiatives. In 2014, approximately 31% of Empire's electricity generation was from coal-fired generation facilities, all of which were environmentally compliant. In the long term, Algonquin expects that there will continue to be reductions in coal-fired electrical generation and that energy will increasingly be generated by a combination of additional gas-fired and renewable power generation. Given its experience in this field, Algonquin expects to be an active participant in any future renewable power generation. Such participation could involve the combined company self-delivering new power generation capacity additions of natural gas, solar, wind, and other renewable generation which are expected to be rate base eligible investments.

Experienced Management Team

Algonquin believes that Empire and Algonquin have complementary management teams and corporate cultures focused on safety, customer service and long-term value creation that will support a smooth combination of the two companies.

Empire is a well-run utility that has an experienced management team, with its senior officers averaging nearly 20 years of experience with Empire. The management team has demonstrated leadership through the operation of a large, well-run diversified utility company providing safe, reliable and cost-effective electric, gas and water service to its customers. Algonquin believes that its existing Missouri utility operations can benefit from and be managed by this experienced Empire management team.

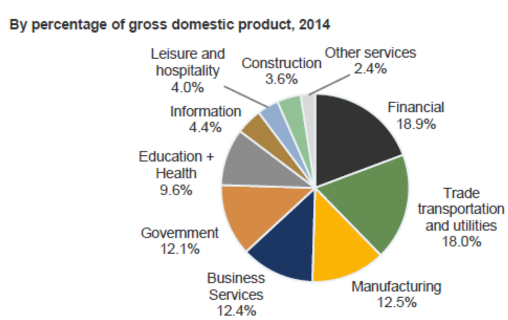
Empire's accomplished management team will fortify the leadership of its central-U.S. utility operations and provide an opportunity to consolidate these regional operations under Empire's senior management. Regional expertise in operations and project development is an asset that Algonquin believes can be leveraged to pursue potential project partnerships and future acquisition opportunities outside the jurisdictions in which Empire and Algonquin currently operate.

Empire's management team has a demonstrated track record of working productively with regulators and policy makers to obtain successful regulatory outcomes for all stakeholders. Algonquin believes that Empire's management has also fostered strong relationships with its employees, resulting in a low employee turnover, ability to recruit strong employees and few labour relations issues.

Favourable Missouri Economic Indicators

Empire's operations are located predominately in Missouri; approximately 91% of its retail revenues come from the state. As the global economy remains uncertain, the U.S. as a market remains attractive with relatively low risk and relatively positive economic outlook compared to alternative markets. Missouri is experiencing a corresponding economic improvement, with a number of economic indicators trending in a positive direction.

Missouri is well-positioned within the larger U.S. economy as a regional hub for financial, medical, education, transportation, manufacturing and retail developments. The following chart shows Missouri's key industries by percentage of GDP in 2014.



Notes:

(1) Source: 2015 Missouri Economic Report, Missouri Department of Economic Development

Missouri also possesses a growing working population, as its total labour force increased by approximately 50,000 workers between 2011 and 2015. Missouri's unemployment rate has also decreased significantly in the last several years, consistent with the U.S. national trend, from approximately 9.8% in January of 2010 to 5.8% in May of 2015 according to a report by the Missouri Department of Economic Development. The same report shows real personal income in the state has grown over the last decade, also tracking the national trend.

THE ACQUIRED BUSINESS

Unless otherwise indicated by the context, "Empire" means The Empire District Electric Company and its subsidiaries, and references to individual subsidiaries of The Empire District Electric Company refer to that company and its respective subsidiaries.

Empire

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, with approximately 218,000 customers in Missouri, Kansas, Oklahoma, and Arkansas. Empire, a Kansas corporation organized in 1909, is an operating public utility with its common stock listed on the NYSE under the ticker symbol "EDE". Empire's gross operating revenues in 2014 were derived as follows:

Electric segment sales*	90.8%
Gas segment sales	8.0
Other segment sales	1.2

* Includes 0.3% from the sale of water.

Results of Operations

The following table represents Empire's net income by operating segment for the periods presented as follows:

(millions) (US$)	Nine Months ended September 30, 2015	Year ended December 31, 2014	Year ended December 31, 2013
Electric	$ 43.8	$ 61.5	$ 58.6
Gas	0.7	2.9	2.3
Other	2.2	2.7	2.5
Net income	$ 46.7	$ 67.1	$ 63.4

For further information on the financial condition and results of Empire, reference is made to the audited comparative consolidated financial statements of Empire as at December 31, 2014 and 2013, including the consolidated balance sheets and the related consolidated statements of income, common stockholders' equity and cash flows, for each of the years ended December 31, 2014 and 2013, and the unaudited interim comparative consolidated financial statements of Empire for the three and nine months ended September 30, 2015, each of which is included in this Prospectus.

Electric Segment

Empire's electric operations cover a service territory of approximately 10,000 square miles, located principally in southwestern Missouri, and also include smaller areas in southeastern Kansas, northeastern Oklahoma and northwestern Arkansas. Empire supplies electric service to customers in 119 incorporated communities and to various unincorporated areas and at wholesale to four municipally-owned distribution systems. The largest urban area served is the city of Joplin, Missouri, and its immediate vicinity, with a population of approximately 160,000. As of December 31, 2014, Empire's electric operations served approximately 170,000 customers.

In its electric service territories, Empire operates under franchise agreements having original terms of a minimum of 20 years in virtually all of the incorporated communities. Approximately 55% of the electric operating revenues in 2014 were derived from incorporated communities with franchises having at least ten years remaining and approximately 15% were derived from incorporated communities in which the franchises have remaining terms of ten years or less. Although the franchise agreements contain no renewal provisions, in recent years, Empire has obtained renewals of all expiring electric franchises prior to the expiration dates.

Electric on-system operating revenues for the years ended 2014, 2013, and 2012 were comprised of the following customer classes:

	2014	2013	2012
Residential	43.4%	43.9%	43.5%
Commercial	31.6	31.3	32.2
Industrial	15.5	15.5	16.0
Wholesale on-system	4.1	3.9	3.8
Miscellaneous sources[(1)]	2.8	2.9	2.8
Other electric revenues	2.6	2.5	1.7

Notes:

(1) Primarily other public authorities.

kWh Sales

Kilowatt-hour ("**kWh**") sales by major customer class for on-system sales were as follows (kWhs in millions):

Customer Class	Nine Months ended September 30, 2015	Year ended December 31, 2014	Year ended December 31, 2013
Residential	1,451.1	1,950.4	1,936.6
Commercial	1,208.1	1,583.8	1,541.7
Industrial	804.3	1,031.6	1,015.5
Wholesale on-system	255.3	336.3	343.1
Other[(1)]	99.2	128.0	129.4
Total on-system sales	3,818.0	5,030.1	4,966.3

Notes:

(1) Other kWh sales include street lighting, other public authorities and interdepartmental usage.

As of December 31, 2014 Empire's largest single on-system wholesale customer was the city of Monett, Missouri, which in 2014 accounted for approximately 2.9% of electric revenues. No single retail customer accounted for more than 1.8% of electric revenues in 2014.

As a vertically-integrated regulated utility, the primary drivers of Empire's electric operating margins (defined as electric revenues less fuel and purchased power costs) are: (1) rates Empire can charge its customers, including timing of new rates; (2) weather; (3) customer growth and usage; and (4) general economic conditions. The utility commissions in the states in which Empire operates, as well as the FERC, set the rates which it can charge its customers. In order to offset expenses, Empire depends on its ability to receive adequate and timely recovery of its costs (primarily fuel and purchased power and construction costs) and/or rate relief. Empire assesses the need for rate relief in all of the jurisdictions it serves and files for such relief when necessary. The effects of timing of rate relief are discussed in detail in Note 3 in the notes to Empire's audited comparative consolidated financial statements included in this Prospectus. Of the factors driving margins, weather has the greatest short-term effect on the demand for electricity for Empire's regulated business. Very hot summers and very cold winters increase electric demand, while mild weather reduces demand. Residential and commercial sales are impacted more by weather than industrial sales, which are mostly affected by business needs for electricity and by general economic conditions.

Revenues and Gross Margin

Electric segment operating revenues by major customer class for on-system and off-system sales, and the associated fuel and purchased power expense (including a reconciliation of Empire's actual fuel and purchased power expenditures to the fuel and purchased power expense shown on Empire's statements of income) were as follows (dollars in U.S. millions):

	Electric Segment Operating Revenues and Gross Margin		
Customer Class	**Nine Months ended September 30, 2015**	**Year ended December 31, 2014**	**Year ended December 31, 2013**
Residential	$ 181.3	$ 236.5	$ 227.7
Commercial	132.3	172.3	162.4
Industrial	67.7	84.7	80.5
Wholesale on-system	13.9	22.3	20.0
Other(1)	12.0	15.2	15.0
Total on-system revenues	407.2	531.0	505.6
Off-system wholesale(2)	—	3.2	15.5
SPP IM net revenues(2)	12.1	41.9	—
Total revenues from kWh sales	419.3	576.1	521.1
Miscellaneous revenues(3)	10.5	14.3	13.2
Total electric operating revenues	$ 429.8	$ 590.4	$ 534.3
Water revenues	1.5	2.1	2.1
Total electric segment operating revenues	**$ 431.3**	**$ 592.5**	**$ 536.4**
Actual fuel and purchased power expenditures	$ 111.0	$ 165.2	$ 182.1
SPP IM net purchases(2)	17.5	55.9	—
Net fuel recovery and deferral	7.5	(3.8)	(3.6)
SWPA amortization(4)	(1.9)	(2.6)	(2.8)
Unrealized (gain)/loss on derivatives	(0.2)	0.4	(0.3)
Total fuel and purchased power expense per income statement	133.9	215.1	175.4
Total Gross Margin	**$ 297.4**	**$ 377.4**	**$ 361.0**

Notes:

(1) Other operating revenues include street lighting, other public authorities and interdepartmental usage.

(2) The SPP IM (as defined in this Prospectus) was implemented on March 1, 2014. As of December 31, 2014, off-system revenues were effectively replaced by SPP IM activity. See "Markets and Transmission" in the notes to Empire's audited comparative consolidated financial statements included in this Prospectus for more information.

(3) Miscellaneous revenues include transmission service revenues, late payment fees, renewable energy credit sales, rent, etc.

(4) Missouri ten year amortization of the US$26.6 million payment received from the SWPA (as defined in this Prospectus) in September, 2010, of which US$11.1 million of the Missouri portion remains to be amortized as of September 30, 2015.

Gas Segment

Empire's gas operations serve customers in northwest, north central and west central Missouri. As of December 31, 2014, Empire's gas operations served approximately 43,500 customers. As of December 31, 2014, Empire provided natural gas distribution to 48 communities and 422 transportation customers. The largest urban area served by Empire's gas operations is the city of Sedalia with a population of over 20,000. Empire operates under gas franchises having original terms of 20 years in virtually all of the incorporated communities. As of December 31, 2014, 18 of the franchises have 10 years or more remaining on their term and 26 of the franchises have less than 10 years remaining on their term. Although Empire gas franchises contain no renewal provisions, in recent years Empire has obtained renewals of all expiring gas franchises prior to the expiration dates.

Empire's gas operating revenues in 2014 were derived as follows:

Residential	63.4%
Commercial	26.3
Industrial	1.0
Transportation	7.7
Miscellaneous	1.6

No single retail customer accounted for more than 1% of gas revenues in 2014.

The primary drivers of Empire's gas operating revenues are: (1) rates Empire can charge its customers, (2) weather, (3) customer growth and usage, (4) the cost of natural gas and interstate pipeline transportation charges and (5) general economic conditions. The MPSC sets the rates which Empire can charge its customers. In order to offset expenses, Empire depends on its ability to receive adequate and timely recovery of its costs (primarily commodity natural gas) and/or rate relief. Empire assesses the need for rate relief and files for such relief when necessary. A Purchased Gas Adjustment ("**PGA**") clause is included in its gas rates, which allows Empire to recover its actual cost of natural gas from customers through rate changes, which are made periodically (up to four times) throughout the year in response to weather conditions, natural gas costs and supply demands. Weather affects the demand for natural gas. Very cold winters increase demand for gas, while mild weather reduces demand. Due to the seasonal nature of the gas business, revenues and earnings are typically concentrated in the November through March period, which generally corresponds with the heating season.

The following table details Empire's natural gas sales for the nine months ended September 30, 2015 and years ended December 31, 2014 and 2013:

	Total Gas Delivered to Customers		
(bcf sales)	**Nine Months ended September 30, 2015**	**Year ended December 31, 2014**	**Year ended December 31, 2013**
Residential	1.59	2.76	2.74
Commercial[(1)]	0.76	1.27	1.35
Industrial	0.03	0.06	0.07
Other[(2)]	0.02	0.04	0.04
Total retail sales	2.40	4.13	4.20
Transportation sales[(1)]	3.31	4.92	4.53
Total gas operating sales	5.71	9.05	8.73

Notes:

(1) Several commercial customers transferred to transportation customers during 2014, reflecting the decrease in commercial sales and the increase in transportation sales.

(2) Other includes other public authorities and interdepartmental usage.

The following table details Empire's natural gas revenues for the nine months ended September 30, 2015 and years ended December 31, 2014 and 2013:

	Operating Revenues and Cost of Gas Sold		
($ in U.S. millions)	**Nine Months ended September 30, 2015**	**Year ended December 31, 2014**	**Year ended December 31, 2013**
Residential	19.6	$ 32.9	$ 31.6
Commercial[1]	8.0	13.6	13.7
Industrial	0.3	0.5	0.5
Other[2]	0.3	0.4	0.3
Total retail revenues	$ 28.2	$ 47.4	$ 46.1
Other revenues	0.3	0.4	0.4
Transportation revenues[1]	2.7	4.0	3.5
Total gas operating revenues	$ 31.2	$ 51.8	$ 50.0
Cost of gas sold	14.8	27.0	25.8
Gas segment gross margins	$ 16.4	$ 24.8	$ 24.2

Notes:

(1) Several commercial customers transferred to transportation customers during 2014, reflecting the decrease in commercial revenues and the increase in transportation revenues.

(2) Other includes other public authorities and interdepartmental usage.

Other Segment

Empire's other segment consists of its fiber optics business. As of December 31, 2014, Empire had 121 fiber optics customers.

Electric Generating Facilities and Capacity

As of December 31, 2014, Empire's generating capacity consisted of approximately 1.326 MW of generating capacity which consisted of 66.1% natural gas, 32.7% coal and 1.2% hydro. As of December 31, 2014, Empire supplemented its on-system generating capacity with purchases of capacity and energy from other sources in order to meet the demands of its customers and the applicable capacity margins under pooling agreements and National Electric Reliability Council rules. As of December 31, 2014, Southwest Power Pool Organization ("**SPP**") required its members (including Empire) to maintain a minimum 12% capacity margin.

At December 31, 2014, Empire's owned generating plants consisted of:

Plant	Ownership	Capacity (MW)(1)	Primary Fuel
State Line Combined Cycle	60%	297(2)	Natural Gas
Riverton — Natural Gas	100%	226(3)	Natural Gas
Empire Energy Center	100%	260	Natural Gas
State Line Unit No. 1	100%	93	Natural Gas
Asbury	100%	194(4)	Coal
Iatan	12%	190(2)	Coal
Plum Point Energy Station	7.52%	50(2)	Coal
Ozark Beach	100%	16	Hydro
TOTAL		1,326	

Notes:

(1) Based on summer rating conditions as utilized by SPP.

(2) Capacity reflects Empire's allocated shares of the capacity of these plants.

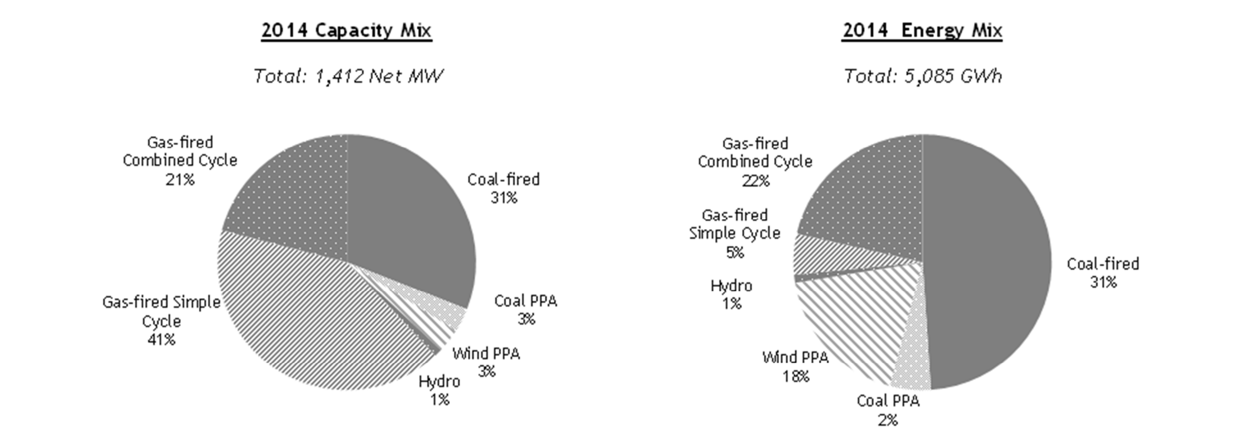
(3) Reflects the retirement of Riverton Unit 7 on June 30, 2014. Capacity was reduced to approximately 175 MW concurrent with the retirement of Riverton Units 8 and 9 on June 30, 2015. The Unit 12 combined cycle project is expected to add an estimated 108 MW upon completion in early to mid-2016.

(4) Includes additional auxiliary MW needed for AQCS and turbine retrofit.

Empire has an agreement, which expires in 2039, for the purchase of 50 MW of capacity from the Plum Point Energy Station ("**Plum Point**"), a 670-MW, coal-fired generating facility near Osceola, Arkansas. Empire began receiving purchased power under this agreement on September 1, 2010. Separately, Empire owns an undivided interest of 50 MW of Plum Point's capacity.

Empire has a long-term PPA, which expires in 2028, with Cloud County Windfarm, LLC, owned by EDP Renewables North America LLC, Houston, Texas to purchase the energy generated at the approximately 105-MW Phase 1 Meridian Way Wind Farm located in Cloud County, Kansas. Empire also has a long-term contract, which expires in 2025, with Elk River Windfarm, LLC, owned by Iberdrola Renewables, Inc., to purchase the energy generated at the 150-MW Elk River Windfarm located in Butler County, Kansas. Empire does not own any portion of either windfarm.

The following charts represent Empire's 2014 capacity mix and energy mix from both wholly-owned facilities and purchased capacity from contracted facilities:



Operationally, Empire participates in the SPP IM to meet its energy and ancillary service requirements. Empire's generation resources are offered into the marketplace. The marketplace solution determines what offered resources are committed and dispatched to meet region-wide demand, energy, and ancillary service requirements. To the extent other resources offered to the marketplace are more economic than Empire's resources, they will be utilized for Empire's load, lowering Empire's cost compared to meeting requirements with only Empire's resources.

Empire, like most other U.S. electric utilities with interstate transmission facilities, has placed its facilities under the FERC regulated open access tariffs that provide all wholesale buyers and sellers of electricity the opportunity to procure transmission services (at the same rates) that the utilities provide themselves. Empire is a member of the Southwest Power Pool Regional Transmission Organization ("**SPP RTO**").

The following chart sets forth Empire's purchase commitments and its anticipated owned capacity (in MW) during the indicated years as of December 31, 2014. The capacity ratings Empire uses for its generating units are based on summer rating conditions under SPP guidelines. The portion of the purchased power that may be counted as capacity from Elk River Windfarm, LLC and Cloud County Windfarm, LLC is included in this chart. Because the wind power is an intermittent, non-firm resource, SPP rating criteria does not allow Empire to count a substantial amount of the wind power as capacity.

Year	Purchased Power Commitment[(1)]	Anticipated Owned Capacity	Total Megawatts
2015	86	1326	1412
2016	86	1377[(2)]	1463[(2)]
2017	86	1377	1463
2018	86	1377	1463
2019	86	1377	1463

Notes:

(1) Includes 17 MW for the windfarm operated by Elk River Windfarm, LLC and 19 MW for the windfarm operated by Cloud County Windfarm, LLC.

(2) Reflects the retirement of Riverton Units 8 and 9 and conversion of Riverton Unit 12 to a combined cycle.

Gas Facilities

At December 31, 2014, Empire's principal gas utility properties consisted of approximately 87 miles of transmission mains and approximately 1,175 miles of distribution mains.

The following table sets forth the three pipelines that serve Empire's gas customers:

Service Area	Name of Pipeline
South	Southern Star Central Gas Pipeline
North	Panhandle Eastern Pipe Line Company
Northwest	ANR Pipeline Company

Capital Expenditures

Empire's total capital expenditures, excluding allowance for funds used during construction ("**AFUDC**") and expenditures to retire assets, were US$207.2 million in 2014. Empire's capital expenditures for the nine months ended September 30, 2015 were approximately US$143.5 million.

Empire also has in place a contract with a third party vendor to complete engineering, procurement, and construction activities at its Riverton plant to convert Riverton Unit 12 from a simple cycle combustion turbine to a combined cycle unit. The conversion will include the installation of a heat recovery steam generator, steam turbine generator, auxiliary boiler, cooling tower, and other auxiliary equipment. The Air Emission Source Construction Permit necessary for this project was issued by Kansas Department of Health and Environment on July 11, 2013. This conversion is currently scheduled to be completed in early to mid-2016 at a cost estimated to range from US$165 million to US$175 million, excluding AFUDC. Construction costs, consisting of pre-engineering, site preparation activities and contract costs incurred on the project to date through September 30, 2015 were US$150 million, excluding AFUDC.

Fuel and Natural Gas Supply

Electric Segment

Below are the total fuel requirements for Empire's generating units in 2014 and 2013 (based on kWh generated):

	2014	2013
Coal	63.7%	65.9%
Natural gas	35.8	34.0
Fuel oil	0.4	0.1
Tire derived fuel	0.1	0.0

Empire's Asbury plant is fueled primarily by coal with oil being used as start-up fuel. In 2014, Asbury burned a coal blend consisting of approximately 91.4% Western coal (Powder River Basin) and 8.6% blend coal on a tonnage basis. Empire's average coal inventory target at Asbury is approximately 60 days. As of December 31, 2014, Empire had sufficient coal on hand to supply full load requirements at Asbury for 44 – 277 days, as compared to 38 – 59 days as of December 31, 2013, depending on the actual blend ratio. The inventory increased during 2014 as Asbury rebuilt its stockpile during the AQCS outage.

Empire satisfied 63.7% of its 2014 generation fuel supply need through coal. Approximately 96% of its 2014 coal supply was Western coal. Empire has contracts and binding proposals to supply a portion of the fuel for its coal plants through 2017. As of September 30, 2015, these contracts satisfied approximately 100% of Empire's anticipated fuel requirements for the remainder of 2015, 35% for 2016 and 18% for 2017 for the Asbury plant.

All of the Western coal used at Empire's Asbury plant is shipped by rail, a distance of approximately 800 miles. Empire has a coal transportation agreement with the BNSF Railway Company and the Kansas City Southern Railway Company which runs through 2019. As of September 30, 2015, Empire had short-term operating leases for two unit trains to meet coal delivery demands. Additional train capacity is leased on an as needed basis.

Unit 1 and Unit 2 at the Iatan Plant are coal-fired generating units which are jointly-owned by Kansas City Power and Light Company (“**KCP&L**”), a subsidiary of Great Plains Energy, Inc., Missouri Joint Municipal Electric Utility Commission, Kansas Electric Power Cooperative and Empire, with its share of ownership being 12% in each of Unit 1 and Unit 2. KCP&L is the operator of these plants and is responsible for arranging their fuel supply. As of December 31, 2014, KCP&L had secured contracts for low sulfur Western coal in quantities sufficient to meet approximately 40% of Iatan’s requirements for 2016 and 10% for 2017. Coal is transported to Iatan by rail. KCP&L’s rail contract provides transportation services through December 31, 2018.

Plum Point is a 670-MW, coal-fired generating facility near Osceola, Arkansas. Empire owns, through an undivided interest, 50 MW of the plant’s capacity. Effective September 2015, NRG Energy Services LLC is the operator of this plant. Plum Point Services Company, LLC (“**PPSC**”), the project management company acting on behalf of the joint owners, is responsible for arranging its fuel supply. As of December 31, 2014, PPSC has secured contracts for low sulfur Western coal in quantities sufficient to meet approximately 87% of Plum Point’s requirements for 2016 and 48% for 2017. Empire has a 15-year lease agreement, expiring in 2024, for 54 railcars for its ownership share of Plum Point and another 15-year lease agreement, expiring in 2025, for an additional 54 railcars associated with its Plum Point PPA.

Since its transition from coal in 2012, Empire’s Riverton plant is fueled primarily by natural gas with oil available as backup for certain units. Based on kWh generated during 2014, Riverton’s generation was 100% natural gas.

Empire’s Energy Center and State Line Unit No.1 combustion turbine facilities (not including the State Line Combined Cycle (“**SLCC**”) Unit, which is fueled 100% by natural gas) are fueled primarily by natural gas with oil also available for use primarily as backup. Based on kWh generated during 2014, 96.1% of the Energy Center generation was produced from natural gas and 65% of the State Line Unit No. 1 generation came from natural gas with the remainder being fuel oil. As of December 31, 2014, oil inventories were sufficient for approximately 5 days of full load operation on Units No. 1, 2, 3 and 4 at the Energy Center and 5 days of full load operation for State Line Unit No. 1. As typical oil usage is minimal, these inventories are sufficient for Empire’s current requirements.

Empire has firm transportation agreements with Southern Star Central Pipeline, Inc. (“**Southern Star**”) with current expiration dates of July 30, 2017, for the transportation of natural gas to the SLCC. This date is adjusted for periods of contract suspension by Empire during outages of the SLCC. Empire reached agreement with Southern Star to replace these firm transportation agreements effective April 1, 2016 with a new agreement that runs through October 2022. Empire has additional firm transportation agreements that provide firm transportation to its Riverton plant sufficient to supply Empire’s Riverton Unit 12 through August 2019. These transportation agreements can also supply natural gas to State Line Unit No. 1, the Empire Energy Center or the Riverton plant, as elected by Empire on a secondary basis. Empire expects transportation agreements will serve nearly all of its natural gas transportation needs for its generating plants over the next several years. Any remaining gas transportation requirements, although small, will be met by utilizing capacity release on other holder contracts, interruptible transport, or delivered to the plants by others.

The majority of Empire’s physical natural gas supply requirements will be met by short-term forward contracts and spot market purchases. Forward natural gas commodity prices and volumes are hedged several years into the future in accordance with Empire’s Risk Management Policy in an attempt to lessen the volatility in its fuel expenditures and gain predictability. In addition, Empire has an agreement with Southern Star to purchase one million Dekatherms (Dth) of firm gas storage service capacity for a period of five years, expiring in April 2016. The reservation charge for this storage capacity is approximately US$1.1 million annually.

Gas Segment

Empire has agreements with many of the major suppliers in both the Midcontinent and Rocky Mountain regions that provide it with both supply and price diversity. Empire continues to expand its supplier base to enhance supply reliability as well as provide for increased price competition.

Regulation and Regulatory Matters

Electric Segment

As a public utility, Empire's electric segment operations are subject to regulation by the MPSC, the State Corporation Commission of the State of Kansas ("**KCC**"), the Corporation Commission of Oklahoma ("**OCC**") and the Arkansas Public Service Commission ("**APSC**" and together with the MPSC, KCC and OCC, the "**State Commissions**") with respect to services and facilities, rates and charges, regulatory accounting, valuation of property, depreciation and various other matters. Each such State Commission has jurisdiction over the creation of liens on property located in its state to secure bonds or other securities. The KCC also has jurisdiction over the issuance of all securities because Empire is a regulated utility incorporated in Kansas. Empire's transmission and sale at wholesale of electric energy in interstate commerce and Empire's facilities are also subject to the jurisdiction of the FERC, under the Federal Power Act. FERC jurisdiction extends to, among other things, rates and charges in connection with such transmission and sale; the sale, lease or other disposition of such facilities and accounting matters.

Empire routinely assesses the need for rate relief in all of the jurisdictions it serves and files for such relief when necessary. Empire's rates for retail electric and natural gas services (other than specially negotiated retail rates for industrial or large commercial customers, which are subject to regulatory review and approval) are determined on a "cost of service" basis. Rates are designed to provide, after recovery of allowable operating expenses, an opportunity for Empire to earn a reasonable return on "rate base". "Rate base" is generally determined by reference to the original cost (net of accumulated depreciation and amortization) of utility plant in service, subject to various adjustments for deferred taxes and other items. Over time, rate base is increased by additions to utility plant in service and reduced by depreciation, amortization and retirement of utility plant or write-off's as ordered by the utility commissions. In general, a request of new rates is made on the basis of a "rate base" as of a date prior to the date of the request and allowable operating expenses for a 12-month test period ended prior to the date of the request. Although the current rate making process provides recovery of some future changes in rate base and operating costs, it does not reflect all changes in costs for the period in which new retail rates will be in place. This results in a lag (commonly referred to as "regulatory lag") between the time Empire incurs costs and the time when it can start recovering the costs through rates.

Typical fuel adjustment clauses permit the distribution to customers of changes in fuel costs, subject to routine regulatory review, without the need for a general rate proceeding. Fuel adjustment clauses are presently applicable to Empire's retail electric sales in Missouri, Oklahoma and Kansas and system wholesale kWh sales under FERC jurisdiction. Empire has an Energy Cost Recovery Rider in Arkansas that adjusts for changing fuel and purchased power costs on an annual basis.

Empire filed its Integrated Resource Plan ("**IRP**") with the MPSC on July 1, 2013. The IRP analysis of future loads and resources is normally conducted once every three years. On March 12, 2014, the MPSC issued an order approving its IRP, effective March 12, 2014.

Empire's IRP supports the compliance plan and strategy ("**Compliance Plan**") Empire is implementing in order to comply with current and forthcoming environmental regulations. The Mercury Air Toxic Standards ("**MATS**") and the Clean Air Interstate Rule ("**CAIR**"), replaced by the Cross State Air Pollution Rule ("**CSAPR**"), are the drivers behind the Compliance Plan and its implementation schedule. The CSAPR was first proposed by the Environmental Protection Agency ("**EPA**") in July 2010 as a replacement of CAIR and came into effect on January 1, 2015. As at September 30, 2015, Empire was in material compliance with CSAPR and expects to be able to meet all applicable, future CSAPR requirements. The MATS require reductions in mercury, acid gases and other emissions considered hazardous air pollutants. They became effective in April 2012 and required full compliance by April 16, 2015. As at September 30, 2015, Empire was in material compliance with MATS. However, in June 2015, the U.S. Supreme Court remanded the MATS back to the D.C. Circuit Court, holding that the EPA must consider cost (including cost of compliance) before deciding whether the regulation is appropriate and necessary. The court noted that it will be up to the EPA to decide within the limits of reasonable interpretation how to account for cost. MATS remains in effect until the D.C. Circuit Court acts. Accordingly, Empire and other entities subject to MATS must comply with its terms absent further relief granted. Empire anticipates compliance costs associated with the MATS, CAIR and CSAPR regulations to be recoverable in its rates.

On August 29, 2014, Empire filed a request with the MPSC for changes in rates for its Missouri electric customers, seeking an annual increase in total revenue of approximately US$24.3 million, or approximately 5.5%. The main cost drivers in the rate increase were the costs associated with the environmental retrofit project at Empire's Asbury plant that were incurred to comply with the EPA rules governing the continued operation of the plant, increases in property taxes, increases in ongoing maintenance expenses and increases in Regional Transmission Organization transmission fees. On June 24, 2015, the MPSC granted new rates for Missouri customers, effective on July 26, 2015. The order approved an annual increase in base revenues of about US$17.1 million or 3.90%, which included a net reduction in base fuel and purchased power of US$1.60 per MWh, consistent with the non-unanimous stipulation and agreement filed April 8, 2015. The order established a tracking mechanism for expenses related to the Riverton Unit 12 long-term maintenance contract; continued tracking of pension and other postemployment benefit expenses; and discontinued tracking of vegetation management expenses and Iatan 2, Iatan Common and Plum Point operating and maintenance costs. In addition, the order provided for the tracking and recovery of certain future changes in total transmission expense through the Fuel Adjustment Charge, which Empire estimates at approximately 34% of such changes.

On May 20, 2014, Empire filed a settlement agreement with the APSC for an increase of US$1.375 million, or approximately 11%. A hearing was held on the settlement agreement on July 22, 2014. On September 16, 2014, the APSC issued an order approving the settlement with a modification that reduced the overall revenue increase to US$1.367 million. The new rates were effective September 26, 2014. Empire had filed a request on December 3, 2013 with the APSC seeking an annual increase in total revenue of approximately US$2.2 million, or approximately 18%. The rate increase was requested to recover costs incurred to ensure continued reliable service for Empire's customers, including capital investments, operating systems replacement costs and ongoing increases in other operation and maintenance expenses and capital costs.

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

On January 22, 2015, Empire filed an Application with the KCC requesting approval of its Ad Valorem Tax Surcharge. The request sought approval for an annual increase of US$0.27 million related to increases in Ad Valorem taxes which exceed amounts currently included in base rates. On February 19, 2015, the KCC approved the request. The new rate was effective on and after February 23, 2015.

On February 23, 2015, Empire filed a notice with the APSC to implement a tariff rider pursuant to the provision of Act 310 of 1981. The rider recovers reasonably incurred costs and expenditures as a direct result of legislative or regulatory requirements relating to the protection of the public health, safety, or the environment. Empire's implemented tariff rider recovers its Arkansas jurisdictional share of investment associated with the Asbury AQCS. The new tariff is effective upon notice (February 23, 2015) subject to refund.

On July 24, 2015, Empire filed a motion to withdraw its Missouri Energy Efficiency Investment Act filing ("**MEEIA**"). Empire will continue its current portfolio of Energy Efficiency programs, with recovery through base rates. Empire will review the need for a future MEEIA filing in conjunction with its 2016 IRP.

On July 31, 2015, Empire filed a notice updating its most recent IRP, with the MPSC. In the notice Empire indicated that Riverton Units 8 and 9 were retired on June 30, 2015. The notice also provides additional information on Empire's MEEIA application withdrawal mentioned above.

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

On October 16, 2015, Empire filed a request with the MPSC for changes in rates for its Missouri electric customers. Empire is seeking an annual increase in total revenue of approximately US$33.4 million, or approximately 7.3%. The most significant factor driving the rate request is the cost associated with the conversion of the Riverton Unit 12 natural gas combustion turbine to combined cycle operation.

On June 8, 2015, the governor of the State of Oklahoma approved an administrative ruling that provides customer rate reciprocity to electric companies who serve less than 10% of total customers within the State of Oklahoma. As a result, future increases in Missouri customer rates approved by the MPSC will be effective for Empire's Oklahoma customers, subject to OCC approval. On October 26, 2015, Empire filed a request with the OCC to adopt the Missouri customer electric rates requested in its October 16, 2015 Missouri rate filing discussed above for its Oklahoma customers once approval is granted by the MPSC.

On November 4, 2008, Missouri voters approved the Clean Energy Initiative (Proposition C) which requires Empire and other investor-owned utilities in Missouri to generate or purchase electricity from renewable energy sources, such as solar, wind, biomass and hydro power, or purchase Renewable Energy Credits (RECs), in amounts equal to at least 5% of retail sales in 2014, increasing to at least 15% by 2021. As of September 30, 2015, Empire was in compliance with this regulatory requirement as a result of generation from its Ozark Beach Hydroelectric Project and PPAs with Cloud County Windfarm, LLC, located in Cloud County, Kansas, and Elk River Windfarm, LLC, located in Butler County, Kansas.

Proposition C also requires that 2% of the energy from renewable energy sources must be solar; however, Empire believed that it was exempted by statute from the solar requirement. On January 20, 2013, the Earth Island Institute, d/b/a Renew Missouri, and others challenged Empire's solar exemption by filing a complaint with the MPSC. The MPSC dismissed the complaint and Renew Missouri subsequently filed a notice of appeal seeking review by the Missouri Supreme Court. On February 10, 2015, the Missouri Supreme Court issued an opinion holding that the Missouri legislature had the authority to adopt the statute providing the exemption but reversed the MPSC's holding that the two laws could be harmonized. The statute providing the exemption (which was enacted in August 2008) was impliedly repealed by the adoption of Proposition C because it conflicted with the latter law. On May 6, 2015, the MPSC approved tariffs filed by Empire on May 5, 2015 to establish solar rebate payment procedures and revise Empire's net metering tariffs to accommodate the payment of solar rebates. As of September 30, 2015, Empire had processed 109 solar rebate applications resulting in solar rebate-related costs totaling approximately US$1.6 million under the new tariff. Empire recorded the US$1.6 million as a regulatory asset. The law provides a number of methods that may be utilized to recover the associated expenses. Empire expects any costs to be recoverable in rates.

Gas Segment

As a public utility, Empire's gas segment operations are subject to the jurisdiction of the MPSC with respect to services and facilities, rates and charges, regulatory accounting, valuation of property, depreciation and various other matters. The MPSC also has jurisdiction over the creation of liens on property to secure bonds or other securities.

Empire has a PGA clause in place that allows it to recover from Empire's customers, subject to routine regulatory review, the cost of purchased gas supplies, transportation and storage, including costs associated with the use of financial instruments to hedge the purchase price of natural gas and related carrying costs. This PGA clause allows Empire to make rate changes periodically (up to four times) throughout the year in response to weather conditions and supply demands, rather than in one possibly extreme change per year. Pursuant to the provisions of the PGA clause, the difference between actual costs incurred and costs recovered through the application of the PGA are reflected as a regulatory asset or regulatory liability until the balance is recovered from or credited to customers.

Legal Proceedings

Empire is a party to various claims and legal proceedings arising out of the normal course of its business. Empire regularly analyzes this information, and provides accruals for any liabilities, in accordance with the guidelines presented in the ASC on accounting for contingencies. In the opinion of Empire's management, it is not probable, given the company's defenses, that the ultimate outcome of these claims and lawsuits will have a material adverse effect upon Empire's financial condition, or results of operations or cash flows.

Environmental Matters

Empire is subject to various federal, state, and local laws and regulations with respect to air and water quality and with respect to hazardous and toxic materials and hazardous and other wastes, including their identification, transportation, disposal, record-keeping and reporting, as well as remediation of contaminated sites and other environmental matters. Empire believes that its operations are in material compliance with present environmental laws and regulations. Environmental requirements have changed frequently and become more stringent over time. Empire expects this trend to continue. While Empire is not in a position to accurately estimate compliance costs for any new requirements, it expects any such costs to be material, although recoverable in rates. For additional information on environmental regulations applicable to Empire, see " – Regulation and Regulatory Matters" and "Note 11" in the notes to Empire's audited comparative consolidated financial statements included in this Prospectus.

In December 2014, Empire completed an environmental retrofit at its Asbury plant. The retrofit project included the installation of a pulse-jet fabric filter (baghouse), circulating dry scrubber and powder activated carbon injection system. This new equipment enables Empire to comply with MATS. The Asbury generating facility returned to service prior to February 1, 2015 after completion of the installation of the Air Quality Control System, allowing for its inclusion in a true up period through December 31, 2014 in Empire's Missouri rate case. The total cost of the Asbury environmental retrofit was approximately US$112.0 million, excluding AFUDC.

Liquidity, Capital Resource and Financing Activities

Empire's primary sources of liquidity and financing are cash provided by operating activities, short-term borrowings under its commercial paper program (which is supported by its unsecured revolving credit facility), borrowings from its unsecured revolving credit facility and long-term debt issued under the Indenture of Mortgage and Deed of Trust of The Empire District Electric Company dated as of September 1, 1944, as amended and supplemented (the "**EDE Mortgage**") and the Indenture of Mortgage and Deed of Trust of The Empire District Gas Company dated as of June 1, 2006, as amended and supplemented (the "**EDG Mortgage**"). Historically, Empire has also successfully raised funds, as needed, from the debt and equity capital markets to fund its liquidity and capital resource needs. Summaries of Empire's recent financing activities are set out below:

- Empire had issued US$4.3 million of common stock during the nine months ended September 30, 2015.

- On June 11, 2015, Empire entered into a Bond Purchase Agreement for a private placement of US$60.0 million of 3.59% First Mortgage Bonds due 2030. A delayed settlement occurred on August 20, 2015. The proceeds from the sale of the bonds were used to refinance existing short-term indebtedness and for general corporate purposes. The bonds are subject to the EDE Mortgage.

- On October 20, 2014, Empire entered into a US$200 million 5-year Credit Agreement replacing the former US$150 million Third Amended and Restated Unsecured Credit Agreement dated January 17, 2012. This agreement may be used for working capital, commercial paper back-up and general corporate purposes. The credit facility includes a US$20 million swingline loan sublimit, a US$20 million sublimit for letters of credit issuance and, subject to bank approval, a US$75 million accordion feature and two one-year extensions of the credit facility's maturity date. There were no outstanding borrowings under this agreement at September 30, 2015. However US$16.3 million was used as of September 30, 2015 to back up Empire's outstanding commercial paper.

- On October 15, 2014, Empire entered into a Bond Purchase Agreement for a private placement of US$60.0 million of 4.27% First Mortgage Bonds due December 1, 2044. The delayed settlement occurred on December 1, 2014. The bonds were issued under the EDE Mortgage. Empire used a portion of the proceeds from the sale of the bonds to refinance existing short-term indebtedness.

- On October 30, 2012, Empire entered into a Bond Purchase Agreement for a private placement of US$30.0 million of 3.73% First Mortgage Bonds due 2033 and US$120.0 million of 4.32% First Mortgage Bonds due 2043. The delayed settlement occurred on May 30, 2013. Empire used a portion of the proceeds from the sale of the bonds to redeem all US$98.0 million aggregate principal amount of Empire's Senior Notes, 4.50% Series due June 15, 2013. The bonds are subject to the EDE Mortgage.

Empire's issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by state and federal regulatory bodies including state public service commissions and, in certain cases, the SEC. Empire believes the cash provided by operating activities, together with the amounts available to it under its credit facilities and the issuance of debt and equity securities, will allow it to meet its needs for working capital, pension contributions, its continuing construction expenditures, anticipated debt redemptions, interest payments on debt obligations, dividend payments and other cash needs through the next several years.

Empire will continue to evaluate its need to increase available liquidity based on its view of working capital requirements, including the timing of its construction programs and other factors. See "Risk Factors — Risk Factors Relating to the Post-Acquisition Business and Operations of Algonquin and Empire" for additional information on items that could impact Empire's liquidity and capital resource requirements.

EDE Mortgage Indenture

Substantially all of the property, plant and equipment of Empire (but not its subsidiaries) is subject to the lien of the EDE Mortgage. Restrictions in the EDE Mortgage could affect its liquidity. The principal amount of all series of first mortgage bonds outstanding at any one time under the EDE Mortgage is limited by terms of the mortgage to US$1.0 billion. Based on the US$1.0 billion limit, and its current level of outstanding first mortgage bonds, Empire is limited to the issuance of US$297.0 million of new first mortgage bonds. The EDE Mortgage contains a requirement that for new first mortgage bonds to be issued, Empire's net earnings (as defined in the EDE Mortgage) for any twelve consecutive months within the fifteen months preceding issuance must be two times the annual interest requirements (as defined in the EDE Mortgage) on all first mortgage bonds then outstanding and on the prospective issue of new first mortgage bonds. In addition to the interest coverage requirement, the EDE Mortgage provides that new bonds must be issued against, among other things, retired bonds or 60% of net property additions. The annual interest coverage requirement and retired bonds or 60% of net property additions tests would permit the issuance of up to US$297.0 million of new first mortgage bonds. As of September 30, 2015, Empire was in compliance with all restrictive covenants of the EDE Mortgage.

EDG Mortgage Indenture

The principal amount of all series of first mortgage bonds outstanding at any one time under the EDG Mortgage is limited by terms of the mortgage to US$300.0 million. Substantially all of the property, plant and equipment of The Empire District Gas Company is subject to the lien of the EDG Mortgage. The EDG Mortgage contains a requirement that for new first mortgage bonds to be issued, the amount of such new first mortgage bonds shall not exceed 75% of the cost of property additions acquired after the date of the Missouri Gas acquisition. The mortgage also contains a limitation on the issuance by The Empire District Gas Company of debt (including first mortgage bonds, but excluding short-term debt incurred in the ordinary course under working capital facilities) unless, after giving effect to such issuance, The Empire District Gas Company's ratio of EBITDA (defined as net income plus interest, taxes, depreciation, amortization and certain other non-cash charges) to interest charges for the most recent four fiscal quarters is at least 2.0 to 1.0. As of September 30, 2015, this test would allow Empire to issue approximately US$21.8 million principal amount of new first mortgage bonds at an assumed interest rate of 5.5%. As of September 30, 2015, Empire was in compliance with all restrictive covenants of the EDG Mortgage.

Additional Conditions Respecting Financing

The EDE Mortgage and the Restated Articles of Incorporation, as amended ("**Restated Articles**"), of Empire, specify earnings coverage and other conditions which must be complied with in connection with the issuance of additional first mortgage bonds or cumulative preferred stock, or the incurrence of unsecured indebtedness. Restrictions in the EDE Mortgage are discussed above.

Under Empire's Restated Articles, (a) cumulative preferred stock may be issued only if its net income available for interest and dividends (as defined in its Restated Articles) for a specified twelve-month period is at least 1.5 times the sum of the annual interest requirements on all indebtedness and the annual dividend requirements on all cumulative preferred stock to be outstanding immediately after the issuance of such additional shares of cumulative preferred stock, and (b) so long as any preferred stock is outstanding, the amount of unsecured indebtedness outstanding may not exceed 20% of the sum of the outstanding secured indebtedness plus Empire's capital and surplus. Empire has no outstanding preferred stock. Accordingly, the restriction in Empire's Restated Articles does not currently restrict the amount of unsecured indebtedness that Empire may have outstanding.

Credit Ratings

As at February 12, 2016 Empire's corporate credit ratings and the ratings for its securities were as follows:

	Moody's	**S&P**
Corporate Credit Rating	Baa1	BBB
EDE First Mortgage Bonds	A2	A–
Senior Notes	Baa1	BBB
Commercial Paper	P-2	A-2
Outlook	Stable	Negative

On February 10, 2016, Moody's and S&P reaffirmed Empire's credit ratings and S&P revised Empire's outlook to negative from developing. See "Recent Developments – Credit Rating Reviews".

A security rating is not a recommendation to buy, sell or hold securities. Each rating is subject to revision or withdrawal at any time by the assigning rating organization. Each security rating agency has its own methodology for assigning ratings, and, accordingly, each rating should be considered independently of all other ratings.

Contractual Obligations as at December 31, 2014

Set forth below is information summarizing Empire's contractual obligations as of December 31, 2014. Other pension and postretirement benefit plans are funded on an ongoing basis to match their corresponding costs, per regulatory requirements, and have been estimated for 2015 – 2019 as noted below.

	Payments Due By Period ($ in U.S. millions)				
Contractual Obligations[1]	Total	Less Than 1 Year	1 – 3 Years	3 – 5 Years	More Than 5 Years
Long-term debt (w/o discount)	$ 800.0	$ —	$ 25.0	$ 90.0	$ 685.0
Interest on long-term debt	703.5	41.7	81.5	70.3	510.0
Short-term debt	44.0	44.0	—	—	—
Capital lease obligations	5.8	0.6	1.1	1.1	3.0
Operating lease obligations[2]	3.2	0.7	1.4	1.1	—
Electric purchase obligations[3]	472.4	52.9	77.7	61.3	280.5
Gas purchase obligations[4]	90.7	13.5	19.3	19.3	38.6
Open purchase orders	114.9	29.5	85.4	—	—
Postretirement benefit obligation funding	17.2	5.0	7.1	5.1	—
Pension benefit funding	52.3	12.8	23.8	15.7	—
Other long-term liabilities[5]	3.0	0.1	0.3	0.3	2.3
TOTAL CONTRACTUAL OBLIGATIONS	$ 2,307.0	$ 200.8	$ 322.6	$ 264.2	$ 1,519.4

Notes:

(1) Some of Empire's contractual obligations have price escalations based on economic indices, but Empire does not anticipate these escalations to be significant.

(2) Excludes payments under Empire's PPAs with each of Elk River Wind Farm, LLC and Cloud County Wind Farm, LLC, as payments are contingent upon output of the facilities. Payments under the PPA with Elk River Wind Farm, LLC can run from zero up to a maximum of approximately US$16.9 million per year based on a 20 year average cost and an annual output of 550,000 MWH. Payments under the PPA with Cloud County Wind Farm, LLC can range from zero to a maximum of approximately US$14.6 million per year based on a 20-year average cost.

(3) Includes a water usage contract for Empire's SLCC facility, fuel and purchased power contracts and associated transportation costs, as well as purchased power for 2014 through 2039 for Plum Point.

(4) Represents fuel contracts and associated transportation costs of Empire's gas segment.

(5) Other long-term liabilities primarily represent electric facilities charges paid to City Utilities of Springfield, Missouri of US$11,000 per month over 30 years.

Properties

Electric Segment Facilities

Empire's generating facilities consist of three coal-fired generating plants, four natural gas generating plants and one hydroelectric generating plant. At December 31, 2014, Empire owned generating facilities with an aggregate generating capacity of 1,326 MW.

The Asbury plant, located near Asbury, Missouri, is a coal-fired generating station with a generating capacity as of December 31, 2014 of 194 MW. In 2014, the plant accounted for approximately 15% of Empire's owned generating capacity and accounted for approximately 27.7% of the energy generated by Empire. Routine plant maintenance, during which the entire plant is taken out of service, is scheduled annually, normally for approximately three to four weeks in the spring. Approximately every fifth year, the maintenance outage is scheduled to be extended to approximately six weeks to permit inspection of the Unit No. 1 turbine. When the

Asbury plant is out of service, Empire typically experiences increased purchased power and fuel expenditures associated with replacement energy, which is likely to be recovered through its fuel adjustment clauses.

Empire owns a 12% undivided interest in the coal-fired Unit No. 1 and Unit No. 2 at the Iatan Generating Station located near Weston, Missouri, 35 miles northwest of Kansas City, Missouri, as well as a 3% interest in the site and a 12% interest in certain common facilities. Empire is entitled to 12% of the units' available capacity, currently 85 MW for Unit No. 1 and 105 MW for Unit No. 2, and is obligated to pay for that percentage of the operating costs of the units. KCP&L operates the units for the joint owners.

Empire owns a 7.52% undivided interest in the coal-fired Plum Point located near Osceola, Arkansas. Empire is entitled to 50 MW, or 7.52% of the unit's available capacity.

As of December 31, 2014, Empire's generating plant located at Riverton, Kansas, had four gas-fired combustion turbine units (Units 9, 10, 11 and 12) and one gas-fired steam generating unit (Unit 8) with an aggregate generating capacity of 226 MW. As of June 2015, Units 8 and 9 were retired. Unit 12 is being converted from a simple cycle combustion turbine to a combined cycle unit. As of September 30, 2015, the conversion was scheduled to be completed in early to mid-2016.

Empire's State Line Power Plant, which is located west of Joplin, Missouri, consists of Unit No. 1, a combustion turbine unit with generating capacity, as of December 31, 2014, of 93 MW and a Combined Cycle Unit with generating capacity of 495 MW of which Empire is entitled to 60%, or 297 MW. The Combined Cycle Unit consists of the combination of two combustion turbines, two heat recovery steam generators, a steam turbine and auxiliary equipment. The Combined Cycle Unit is jointly owned with Westar Generating Inc., a subsidiary of Westar Energy, Inc., which owns the remaining 40% of the unit. Empire is the operator of the Combined Cycle Unit and Westar reimburses it for a percentage of the operating costs per Empire's joint ownership agreement. All units at Empire's State Line Power Plant burn natural gas as a primary fuel with Unit No. 1 having the additional capability of burning oil.

Empire has four combustion turbine peaking units at the Empire Energy Center in Jasper County, Missouri, with an aggregate generating capacity of 260 MW. These peaking units operate on natural gas, as well as oil.

Empire's hydroelectric generating plant (FERC Project No. 2221), located on the White River at Ozark Beach, Missouri, has a generating capacity of 16 MW. Empire has a long-term license from the FERC to operate this plant which forms Lake Taneycomo in southwestern Missouri. As part of the U.S. federal *Energy and Water Development Appropriations Act of 2006* (the "**Appropriations Act**"), a new minimum flow pattern was established with the intent of increasing minimum flows on recreational streams in Arkansas. To accomplish this, the level of Bull Shoals Lake was increased an average of five feet. The increase at Bull Shoals will decrease the net head waters available for generation at Ozark Beach by five feet and, thus, reduce Empire's electrical output. Empire estimates the lost production to be up to 16% of its average annual energy production for this unit. The Appropriations Act required the Southwest Power Administration ("**SWPA**"), an agency of the U.S. federal Department of Energy that markets hydroelectric power, in coordination with Empire and its relevant public service commissions, to determine its economic detriment assuming a January 1, 2011 implementation date. On September 16, 2010, Empire received a US$26.6 million payment from the SWPA, which was deferred and recorded as a noncurrent liability. The SWPA payment, net of taxes, is being used to reduce fuel expense for Empire's customers in all its jurisdictions. It is Empire's understanding that the lake level change for Bull Shoals was implemented in July of 2013.

At December 31, 2014, Empire's transmission system consisted of approximately 22 miles of 345 kV lines, 441 miles of 161 kV lines, 745 miles of 69 kV lines and 81 miles of 34.5 kV lines. Empire's distribution system consisted of approximately 6,911 miles of line at December 31, 2014.

Empire's electric generation stations, other than Plum Point, are located on land owned in fee simple. Empire owns a 3% undivided interest as tenant in common in the land for the Iatan Generating Station. Empire owns a similar interest in 60% of the land used for the SLCC Unit. Substantially all of Empire's electric transmission and distribution facilities are located either (1) on property leased or owned in fee simple; (2) over streets, alleys, highways and other public places, under franchises or other rights; or (3) over private property by virtue of easements obtained from the record holders of title. Substantially all of Empire's electric segment property, plant and equipment are subject to the EDE Mortgage.

Empire also owns and operates water pumping facilities and distribution systems consisting of a total of approximately 96 miles of water mains in three communities in Missouri.

Gas Segment Facilities

At December 31, 2014, Empire's principal gas utility properties consisted of approximately 87 miles of transmission mains and approximately 1,175 miles of distribution mains.

Substantially all of Empire's gas transmission and distribution facilities are located either (1) on property leased or owned in fee simple; (2) under streets, alleys, highways and other public places, under franchises or other rights; or (3) under private property by virtue of easements obtained from the record holders of title. Substantially all of Empire's gas segment property, plant and equipment are subject to the EDG Mortgage.

Other Segment

Empire's other segment consists of its leasing of fiber optics cable and equipment (which Empire also uses in its own utility operations).

Markets & Transmission

Electric Segment

Day Ahead Market: On March 1, 2014, the SPP RTO implemented its Integrated Marketplace (or Day-Ahead Market) which replaced the Energy Imbalance Services (EIS) market. The SPP created a single NERC-approved balancing authority (BA) that took over balancing authority responsibilities for its members, including Empire.

As part of the IM, Empire and other SPP members submit generation offers to sell their power and bids to purchase power into the SPP market, with the SPP serving as a centralized commitment and dispatch of SPP members' generation resources. The SPP matches offers and bids based upon operating and reliability considerations. The SPP reports that approximately 90%-95% of all next day generation needed throughout the SPP territory is being cleared through the IM. Empire also acquires Transmission Congestion Rights (TCR) through annual and monthly processes in an attempt to mitigate congestion costs associated with the power Empire purchases from the IM. When Empire sells more generation to the market than it purchases for a given settlement period, the net sale is included as part of electric revenues. When Empire purchases more generation from the market than it sells, the net purchase is recorded as a component of fuel and purchased power on its financial statements. The net financial effect of these IM transactions is included in Empire's fuel adjustment mechanisms and therefore has little impact on gross margin.

SPP/Midcontinent Independent System Operator ("**MISO**") Joint Operating Agreement and Plum Point Delivery: Due to Plum Point's physical location and interconnection, transmission service from Entergy/MISO is required for delivery. On December 19, 2013, Entergy voluntarily integrated its generation, transmission, and load into the MISO regional transmission organization. Based on the current terms and conditions of MISO membership, Entergy's participation in MISO has increased transmission delivery costs for its Plum Point power station as well as utilizes their transmission system without compensation.

As a result, Empire has participated with the SPP members and other impacted utilities in two separate FERC settlement proceedings to address these important issues in an effort to reduce the costs to its customers. On October 13, 2015, SPP members, SPP, MISO and MISO members filed a settlement at the FERC regarding MISO's unreserved and uncompensated use of the SPP members' systems. The settlement specifically creates, among other provisions, a mechanism where MISO will compensate SPP and the other impacted parties for use of their systems. If approved by the FERC, the agreement will provide governance for the continued shared use of the transmission system among MISO, SPP and the other impacted parties. However, the regional through and out transmission delivery rate (RTOR) dispute regarding Plum Point will go to hearing at the FERC. On May 20, 2015, Empire, along with KCPL-GMO, AECI, and Southern Company filed a formal 206 complaint at the FERC that the ROTR rate was unjust and unreasonable. A procedural schedule was issued by the FERC on October 8, 2015 with hearings to commence on April 25, 2016 and an initial decision scheduled for August 10, 2016.

THE ACQUISITION AGREEMENT

Set forth below is a description of the material terms of the Acquisition Agreement. The description is a summary only and is qualified in its entirety by the full text of the Acquisition Agreement. A copy of the Acquisition Agreement has been filed on the Corporation's SEDAR profile at www.sedar.com. This summary is not intended to be, and should not be relied upon as, disclosure of any facts and circumstances relating to Algonquin or Empire.

The Merger

On February 9, 2016, AcquisitionCo, Merger Sub and Empire entered into the Acquisition Agreement. Upon the terms and subject to the conditions set forth in the Acquisition Agreement, which has been unanimously approved and adopted by the board of directors of Empire, at the effective time of the closing of the Acquisition, Merger Sub will merge with and into Empire (the "**Merger**") with Empire continuing as the surviving corporation. AcquisitionCo is a wholly-owned indirect subsidiary of Algonquin, and Liberty Sub Corp. ("**Merger Sub**") is a wholly-owned direct subsidiary of AcquisitionCo.

The Merger Consideration

Pursuant to the Acquisition Agreement, upon the closing of the Merger, each issued and outstanding share of Empire common stock will be cancelled and converted automatically into the right to receive US$34.00 in cash, without interest (the "**Merger Consideration**"). The aggregate amount of Merger Consideration to be paid, including with respect to outstanding time-vested restricted stock awards ("**Time-Vested RSAs**") and performance based restricted stock awards ("**Performance-Based RSAs**") granted under Empire's stock incentive plans and outstanding common stock units ("**Director Stock Units**") granted under Empire's director stock unit plan, is approximately US$1.5 billion in cash and does not include the assumption of approximately US$0.9 billion of debt on closing of the Acquisition.

Treatment of Restricted Stock Awards, Director Stock Units and Employee Stock Purchase Plan

Upon the closing of the Merger, each outstanding Time-Vested RSA will be cancelled and converted 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 Empire's common stock underlying such Time-Vested RSA, multiplied by (2) the ratio equal to (x) the number of months through the closing date of the Merger (rounding a fraction of a month to the next higher number of whole months) in the restricted period under such Time-Vested RSA, divided by (y) the total number of months in the restricted period under such Time-Vested RSA. Each payment in respect of the Time-Vested RSAs will be made by Empire, as the surviving corporation of the Merger, less applicable tax withholdings, as promptly as practicable following the closing of the Merger.

Upon the closing of the Merger, each outstanding Performance-Based RSA will be cancelled and converted 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 Empire's common stock that would be earned for performance at target over the performance period under such Performance-Based RSA. Each payment in respect of the Performance-Based RSAs will be made by Empire, as the surviving corporation of the Merger, less applicable tax withholdings, as promptly as practicable following the closing of the Merger.

Upon the closing of the Merger, each outstanding Director Stock Unit will be cancelled and converted into the right to receive an amount in cash equal to the Merger Consideration. Each payment in respect of a Director Stock Unit will be made by Empire, as the surviving corporation of the Merger, at the time elected or provided pursuant to the terms and conditions of such Director Stock Unit, together with interest until the date of payment of such amount.

In addition, upon the closing of the Merger, Empire's employee stock purchase plan and the right of any employee to continue participation in such plan and any purchase period under such plan then in effect will terminate. Payment of all remaining, unused amounts credited to each participant's account under such plan, together with interest, will be made by Empire, as the surviving corporation of the Merger, as soon as practicable after the closing of the Merger.

Guarantee by Algonquin

Concurrently with the execution of the Acquisition Agreement, Algonquin delivered to Empire an unconditional and irrevocable guarantee for the full and prompt payment and performance, when due, of all obligations of AcquisitionCo under the Acquisition Agreement.

Representations and Warranties

Under the Acquisition Agreement, Empire, Merger Sub and AcquisitionCo have made various customary representations and warranties.

Empire's representations and warranties relate to, among other things: organization, standing and power of Empire and its subsidiaries; Empire's subsidiaries; capital structure; authority, execution and delivery; enforceability; no conflicts; consents; Empire reports and financial statements; absence of certain changes or events; taxes; employee benefits; labour and employment matters; litigation; compliance with applicable laws; takeover statutes; environmental matters; contracts; real property; intellectual property; insurance; regulatory status; brokers' fees and expenses; and opinion of financial advisor.

The representations and warranties of AcquisitionCo and Merger Sub relate to, among other things: organization, standing and power of AcquisitionCo and Merger Sub; authority, execution and delivery; enforceability; no conflicts; consents; litigation; compliance with applicable laws; financing of the Acquisition; brokers' fees and expenses; capitalization of Merger Sub; ownership of Empire common stock; related persons; regulatory status; and enforceability of the guarantee delivered by Algonquin.

Covenants

Empire and AcquisitionCo have made covenants governing the conduct of the parties to the Acquisition Agreement during the period between signing of the Acquisition Agreement and the closing of the Acquisition, at the closing of the Acquisition, and after the closing of the Acquisition.

Except as set forth in the confidential disclosure schedules to the Acquisition Agreement or otherwise contemplated or required by the Acquisition Agreement or as required by a governmental entity or by applicable law, or with the prior written consent of AcquisitionCo (such consent not to be unreasonably withheld, conditioned or delayed), Empire has agreed, among other things, from the date of the Acquisition Agreement until the closing of the Acquisition to use commercially reasonable efforts to, and to cause each of its subsidiaries to, conduct its business in the ordinary course of business in all material respects and, to the extent consistent with the foregoing, preserve intact, in all material respects, its business organization and existing relationships with governmental entities. Empire is permitted during this period to (i) continue to pursue the rate cases and other proceedings set forth in a disclosure schedule to the Acquisition Agreement, (ii) initiate and pursue new rate cases and certain other proceedings with governmental entities, provided that AcquisitionCo's consent (not to be unreasonably withheld, conditioned or delayed) will be required to the extent any such rate case or proceeding would reasonably be expected to result in an outcome that would be materially adverse to Empire and its subsidiaries, taking into account the requests made by Empire and its subsidiaries in such rate case or proceeding and the resolution of similar recent rate cases or proceedings by Empire and its subsidiaries, (iii) initiate other proceedings with governmental entities in the ordinary course of business and (iv) take any other action contemplated by or described in any filings or other submissions filed or submitted in connection with rate cases and other proceedings with governmental entities in the ordinary course of business existing prior to the date of the Acquisition Agreement.

In addition, during the period from the date of the Acquisition Agreement until the closing of the Acquisition, Empire and its subsidiaries may not, without AcquisitionCo's consent (not to be unreasonably withheld, conditioned or delayed), enter into any settlement or stipulation in respect of any proceeding if such settlement or stipulation would reasonably be expected to result in an outcome that would be materially adverse to Empire and its subsidiaries, taking into account the requests made by Empire and its subsidiaries in such rate case or proceeding and the resolution of similar recent rate cases or proceedings by Empire and its subsidiaries. However, the Acquisition Agreement does not prohibit Empire 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) PGA 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 APSC, the KCC or the OCC.

During the period from the date of the Acquisition Agreement until the closing of the Acquisition, Empire will not, and will not permit any of its subsidiaries to, take any of the following actions (subject to certain exceptions as more particularly described in the Acquisition Agreement) without the prior written consent of AcquisitionCo, which consent shall not be unreasonably withheld, conditioned or delayed, unless expressly permitted in the confidential disclosure schedules to the Acquisition Agreement, or as otherwise contemplated or required by the Acquisition Agreement, or as required by a governmental entity or by applicable law: (i) declare, set aside or pay any dividends on, or make any other distributions (whether in cash, stock or property or any combination thereof), other than quarterly cash dividends on shares of Empire on a schedule and in amounts consistent with Empire's past practices (but without increase in the amount per share); (ii) amend its articles, by-laws or equivalent organizational documents; (iii) split, combine, consolidate, subdivide or reclassify any of its capital stock or 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 Empire or any of its subsidiaries, or any warrants, calls, options or other rights to acquire any such capital stock, securities or interests; (v) issue, deliver, sell, grant, pledge or otherwise encumber or subject to any lien any Empire equity securities or any outstanding indebtedness of Empire having the right to vote (or convertible into, or exchangeable for, securities having the right to vote) on any matters on which shareholders of Empire may vote; (vi) grant to any current or former director, officer or employee of Empire or any of its subsidiaries any increase in compensation or benefits (including paying any amount not due) except in the ordinary course of business and consistent with past practices; (vii) make any material change in financial accounting methods, principles or practices; (viii) make any acquisition or disposition of a material asset or business (including by merger, consolidation, or acquisition of stock or assets); (ix) incur any indebtedness, except in the ordinary course of business, to finance scheduled capital expenditures, to replace existing indebtedness, or to maintain the authorized capital structure of its regulated subsidiaries; (x) make or agree or commit to make, any capital expenditures except certain scheduled capital expenditures or those made in the ordinary course of business; (xi) modify or amend in any material respect, or terminate or waive any material right under any material contract filed with the SEC by Empire or its subsidiaries or enter into any contract that, from and after the closing, purports to bind Algonquin (other than Empire and its 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; (xiii) waive, release, assign, settle or compromise any material claim against Empire or any of its subsidiaries; or (xiv) enter into any contract to do any of the foregoing.

Under the Acquisition Agreement, AcquisitionCo agreed that it will use its reasonable best efforts to take all actions necessary to obtain all governmental and regulatory approvals.

Furthermore, AcquisitionCo has agreed to take, and to cause its affiliates to take, all actions, and to do, or cause to be done, all things necessary to consummate the financing of the Acquisition or to obtain substitute financing sufficient to enable AcquisitionCo to consummate the Acquisition and the other transactions contemplated under the Acquisition Agreement as promptly as possible following the date of the Acquisition Agreement, and, in any event, no later than the closing of the Acquisition. Similarly, from the date of the Acquisition Agreement until the closing or earlier termination of the Acquisition Agreement, subject to certain limitations and unless otherwise agreed by AcquisitionCo, Empire has agreed that it will use its reasonable best efforts to cooperate with AcquisitionCo and its affiliates, as reasonably requested by AcquisitionCo and at AcquisitionCo's expense, in connection with AcquisitionCo's arrangement of its financing for the Acquisition.

AcquisitionCo has agreed that all rights to indemnification, advancement of expenses and exculpation from liabilities for acts or omissions occurring at or prior to the closing of the Acquisition existing in favour of the current or former directors, officers or employees of Empire and its subsidiaries as provided in their respective articles, by-laws or equivalent organizational documents, and any indemnification or other similar contracts of Empire or any of its subsidiaries, in each case, as in effect on the date of the Acquisition Agreement will continue in full force and effect in accordance with their terms (with such rights, after closing of the Acquisition being mandatory rather than permissive, if applicable). In addition, Empire, as the surviving corporation after the Acquisition, will indemnify and hold harmless each director, officer and employee of Empire or any of its subsidiaries who serves in such a role prior to the completion of the Acquisition, against all claims, losses, liabilities, damages, judgments, inquiries, fines and reasonable fees, costs and expenses incurred in connection with any claim arising out of or pertaining to the fact that such individual is or was a director, officer or employee of Empire or any of its subsidiaries. Furthermore, for a period of six years from and after the closing of the Acquisition, subject to certain exceptions, Empire, as the surviving corporation after the Acquisition, shall either cause to be maintained in effect the current policies of directors' and officers' liability insurance and fiduciary liability insurance maintained by Empire or its subsidiaries or (following consultation with AcquisitionCo) provide substitute policies of not less than the existing coverage and having other terms substantially comparable (and not less favourable to the insured persons) to the directors' and officers' liability insurance and fiduciary liability insurance coverage currently maintained by Empire with respect to claims arising from facts or events that occurred on or before the closing of the Acquisition.

Moreover, for a period of two years following closing of the Acquisition, AcquisitionCo shall, and shall cause the corporation surviving the Merger to, provide each individual who is employed by Empire or any of its subsidiaries immediately prior to the closing and who remains employed thereafter by the corporation surviving the Merger (or by AcquisitionCo or its affiliates) with a base salary or wage rate that, in each case, are no less favorable than, and aggregate incentive compensation opportunities and employee benefits that, in each case, are substantially comparable in the aggregate to, those provided to the Empire employee immediately prior to the closing of the Acquisition. In addition, for the period from two years following the closing of the Acquisition to five years following the closing of the Acquisition, AcquisitionCo shall, and shall cause the corporation surviving the Merger to, treat employees employed by the surviving corporation and its subsidiaries with respect to base salary or wage rate, incentive compensation opportunities, employees benefits and severance benefits no less favorably in the aggregate than similarly situated employees of AcquisitionCo and its affiliates.

Closing Conditions

The Acquisition Agreement provides that the obligation of each of AcquisitionCo and Empire to consummate the Acquisition is subject to the satisfaction or waiver (by AcquisitionCo or Empire, as applicable) at or prior to the closing of the Acquisition of the following conditions:

(i) the Acquisition Agreement shall have been approved by the affirmative vote of the holders of a majority of all the outstanding shares of Empire common stock entitled to vote at a duly convened meeting of Empire's common stockholders ("**Empire Shareholder Approval**");

(ii) the governmental and regulatory consents and approvals specified in the Acquisition Agreement required to be obtained by AcquisitionCo and Empire pursuant to the Acquisition shall have been obtained prior to the closing of the Acquisition, including: (A) the approval of the acquisition by each of the State Commissions, FERC, CFIUS and the FCC and (B) the expiration or termination of any applicable waiting period under the HSR Act; and, unless waived by AcquisitionCo, such approvals do not, individually or in the aggregate, have or are 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 purposes, Empire and its subsidiaries), taken as a whole; and

(iii) no law and no judgment, whether preliminary, temporary or permanent, shall be in effect that prevents, makes illegal or prohibits the consummation of the Acquisition.

In addition, the Acquisition Agreement provides that the obligation of Empire to consummate the Acquisition is subject to the satisfaction or waiver (by Empire) at or prior to the closing of the Acquisition of the following conditions:

(i) the representations and warranties of AcquisitionCo and Merger Sub contained in the Acquisition Agreement shall be true and correct (without giving effect to any limitation as to "materiality" or "AcquisitionCo Material Adverse Effect") at and as of closing of the Acquisition 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 "AcquisitionCo Material Adverse

Effect”), individually or in the aggregate, has not had and would not reasonably be expected to have an AcquisitionCo Material Adverse Effect;

“**AcquisitionCo 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 AcquisitionCo or Merger Sub to consummate, or that would reasonably be expected to prevent or materially impede, interfere with or delay AcquisitionCo or Merger Sub’s consummation of, the transactions contemplated by the Acquisition Agreement.

(ii) AcquisitionCo and Merger Sub shall have performed in all material respects all material covenants and agreements required to be performed by them under the Acquisition Agreement at or prior to the closing of the Acquisition; and

(iii) Empire shall have received a certificate signed on behalf of AcquisitionCo by an executive officer of AcquisitionCo certifying the satisfaction by AcquisitionCo and Merger Sub of the conditions set forth in items (i) and (ii) above.

The Acquisition Agreement also provides that the obligation of AcquisitionCo to consummate the Acquisition is subject to the satisfaction or waiver (by AcquisitionCo) at or prior to the closing of the Acquisition of the following conditions:

(i) (A) the representations and warranties of Empire contained in the Acquisition Agreement (except for the representations and warranties pertaining to capital structure) shall be true and correct (without giving effect to any limitation as to “materiality” or “Empire Material Adverse Effect”) at and as of closing of the Acquisition 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 “Empire Material Adverse Effect”), individually or in the aggregate, has not had and would not reasonably be expected to have an Empire Material Adverse Effect; and (B) the representations and warranties of Empire pertaining to capital structure shall be true and correct at and as of the closing of the Acquisition 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;

“**Empire 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 Empire and its 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 an Empire Material Adverse Effect has occurred: (a) any change or condition affecting any industry in which Empire or any of its subsidiaries 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 Empire or any of its subsidiaries 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 the Acquisition Agreement or the pendency of the Acquisition, including (1) any action taken by Empire or any of its subsidiaries that is required or contemplated pursuant to the Acquisition Agreement, or is consented to by AcquisitionCo, or any action taken by AcquisitionCo or any affiliate thereof, to obtain any consent from any governmental entity to the consummation of the Acquisition and the result of any such actions, (2) any claim arising out of or related to the

Acquisition Agreement (including shareholder litigation), (3) any adverse change in supplier, employee, financing source, shareholder, regulatory, partner or similar relationships resulting therefrom or (4) any change that arises out of or relates to the identity of AcquisitionCo or any of its affiliates as the acquirer of Empire; (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 Empire common stock on the NYSE or any change affecting the ratings or the ratings outlook for Empire or any of its subsidiaries, (i) any change in applicable law, regulation or generally accepted accounting principles (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 the Acquisition 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, FCC or any State Commission judgment issued prior to the date of the Acquisition Agreement and applicable to Empire or its subsidiaries; (n) any change or effect arising from (1) any rate cases, including the rate cases and other proceedings set forth in a disclosure schedule to the Acquisition Agreement and rate cases and other proceedings with governmental entities in the ordinary course of business, (2) any requirements imposed by any governmental entities as a condition to obtaining the governmental and regulatory consents and approvals required to be obtained or (3) any other requirements or restrictions imposed by the FERC, FCC or any State Commission on Empire or any of its subsidiaries; or (p) any fact, circumstance, effect, change, event or development that results from any shutdown or suspension of operations at any power plant from which Empire or any of its subsidiaries obtains electricity or facilities from which Empire or any of its subsidiaries 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)(3) above may be taken into account in determining whether an Empire Material Adverse Effect has occurred solely to the extent such fact, circumstance, effect, change, event or development has a materially disproportionate adverse effect on Empire or any of its 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, an Empire Material Adverse Effect, to the extent such change is not otherwise excluded from being taken into account in the specified exceptions above).

(ii) Empire shall have performed in all material respects all material covenants and agreements required to be performed by it under the Acquisition Agreement at or prior to the closing of the Acquisition;

(iii) since the date of the Acquisition Agreement, no fact, circumstance, effect, change, event or development that, individually or in the aggregate has had or would reasonably be expected to have an Empire Material Adverse Effect shall have occurred and be continuing; and

(iv) AcquisitionCo shall have received a certificate signed on behalf of Empire by an executive officer of Empire certifying the satisfaction by Empire of the conditions set forth in items (i), (ii) and (iii) above.

No Solicitation; Empire's Board of Directors Recommendation

Pursuant to the terms of the Acquisition Agreement, Empire shall not, and 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 ("**Representatives**") not to (i) directly or indirectly solicit, initiate or knowingly encourage, induce or facilitate any Takeover Proposal (as defined in this Prospectus) or any inquiry or proposal that would reasonably be expected to lead to a Takeover Proposal, in each case except for the Acquisition Agreement and the transactions contemplated thereby, or (ii) directly or indirectly participate in any discussions or negotiations with any person (except for Empire's affiliates and its and their respective Representatives or AcquisitionCo and AcquisitionCo's affiliates and its and their respective Representatives) regarding, or furnish to any such person, any non-public information with respect to, or cooperate in any way with any such person with respect to any Takeover Proposal or any inquiry or proposal that would reasonably be expected to lead to a Takeover Proposal. Upon signing the Acquisition Agreement, Empire 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 Empire's affiliates and its and their respective Representatives or AcquisitionCo and AcquisitionCo's affiliates and its and their respective Representatives) conducted prior to the date of the Acquisition Agreement with respect to any Takeover Proposal, and 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. If, at any time prior to obtaining Empire Shareholder Approval, Empire receives a bona fide written Takeover Proposal made after the date of the Acquisition Agreement from a third party that does not result from a breach of the Acquisition Agreement and Empire's board of directors determines in good faith (after consultation with outside legal counsel and a financial advisor) that the Takeover Proposal constitutes or could reasonably be expected to lead to a Superior Proposal (as defined below), Empire may (i) furnish information with respect to Empire and its subsidiaries to the person making such Takeover Proposal pursuant to a customary confidentiality agreement (provided that all such information has previously been provided to AcquisitionCo or is provided to AcquisitionCo prior to or substantially concurrently with the provision of such information to such person) and (ii) participate in discussions regarding the terms of such Takeover Proposal. A "**Superior Proposal**" means a bona fide written Takeover Proposal (provided, that for purposes of this definition, the applicable percentage in the definition of Takeover Proposal shall be "more than 50%" rather than "20% or more"), which the Empire board of directors 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 Takeover Proposal and such other factors that are deemed relevant by the Empire board of directors, is more favorable to the holders of Empire common stock than the terms of the Acquisition Agreement (after taking into account any proposed revisions to the terms of the Acquisition Agreement that are committed to in writing by AcquisitionCo).

"**Takeover Proposal**" means any proposal or offer (whether or not in writing), with respect to any (i) merger, consolidation, share exchange, other business combination, recapitalization, liquidation, dissolution or similar transaction involving Empire, (ii) 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 subsidiary of Empire or otherwise) of any business or assets of Empire or its subsidiaries representing 20% or more of the consolidated revenues, net income or assets of Empire and its subsidiaries, taken as a whole, (iii) 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 Empire, (iv) 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 Empire or (v) any combination of the foregoing.

Subject to certain exceptions, neither Empire's board of directors nor any committee thereof shall: (i) withdraw, change, qualify, withhold or modify in any manner adverse to AcquisitionCo, or propose publicly to withdraw, change, qualify, withhold or modify in any manner adverse to AcquisitionCo, its recommendation that Empire's shareholders approve the Acquisition Agreement; (ii) adopt, approve or recommend, or propose publicly to adopt, approve or recommend, any Takeover Proposal; (iii) fail to include in the proxy statement sent to its shareholders relating to the shareholder meeting to be held to vote on approval of the Acquisition Agreement its recommendation that Empire's shareholders approve the Acquisition Agreement; 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) (each of (i), (ii), (iii) and (iv) being an "**Adverse Recommendation Change**"). Subject to certain exceptions, neither Empire's board of directors nor any committee thereof shall authorize, permit, approve or recommend, or propose publicly to authorize, permit, approve or recommend, or allow Empire 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 Takeover Proposal, or requiring, or that would reasonably be expected to cause, Empire to abandon or terminate the Acquisition Agreement.

At any time prior to obtaining the Empire Shareholder Approval, Empire's board of directors may make an Adverse Recommendation Change if (i) any material fact, circumstance, effect, change, event or development has occurred that (A) is unknown to or by the Empire board of directors as of the date of the Acquisition Agreement (or if known, the magnitude or material consequences of which were not known or understood by the Empire board of directors as of the date of the Acquisition Agreement) and (B) becomes known to or by the Empire board of directors prior to obtaining the Empire Shareholder Approval (an "**Intervening Event**") or (ii) Empire has received a Superior Proposal that does not result from a breach of the Acquisition Agreement, and, in each case, if the Empire board of directors determines in good faith (after consultation with outside legal counsel) that the failure to effect an Adverse Recommendation Change as a result of the occurrence of such Intervening Event or in response to the receipt of such Superior Proposal, as the case may be, would reasonably be likely to be inconsistent with the Empire board of directors' fiduciary duties under applicable law; provided, however, that the Empire board of directors may not make such Adverse Recommendation Change unless (1) the Empire board of directors has provided prior written notice to AcquisitionCo that it is prepared to effect an Adverse Recommendation Change in response to the occurrence of the Intervening Event or the receipt of a Superior Proposal, which notice shall, in the case of an Adverse Recommendation Change in response to the receipt of a Superior Proposal, at Empire's option, either attach the most current draft of the proposed acquisition agreement with respect to such Superior Proposal or include a summary of the material terms and conditions of such Superior Proposal, (2) if requested by AcquisitionCo, during the three business day period after delivery of such notice, Empire and its Representatives negotiate in good faith with AcquisitionCo and its Representatives regarding any revisions to the Acquisition Agreement committed to in writing by AcquisitionCo, and (3) at the end of such three business day period and taking into account any changes to the terms of the Acquisition Agreement committed to in writing by AcquisitionCo, Empire's board of directors determines in good faith (after consultation with outside legal counsel) that the failure to make such Adverse Recommendation Change would reasonably be likely to be inconsistent with its fiduciary duties under applicable law. If there has been any subsequent amendment to any material term of such Superior Proposal, the Empire board of directors shall provide a new notice to AcquisitionCo and an additional three business day period from the date of such notice shall apply.

Empire shall promptly advise AcquisitionCo orally and in writing of any Takeover Proposal, the material terms and conditions of any such Takeover Proposal (including the identity of the person making such Takeover Proposal) and shall keep AcquisitionCo 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 Takeover Proposal.

Termination

The Acquisition Agreement may be terminated at any time prior to closing of the Acquisition, whether before or after receipt of the Empire Shareholder Approval, by mutual written consent of AcquisitionCo and Empire.

Additionally, the Acquisition Agreement may be terminated by either AcquisitionCo or Empire at any time prior to closing of the Acquisition, whether before or after receipt of the Empire Shareholder Approval, if:

(i) closing of the Acquisition has not 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 of the Acquisition have been satisfied or waived, as applicable, or shall then be capable of being satisfied (except for conditions that the governmental and regulatory consents and approvals required to be obtained by AcquisitionCo and Empire pursuant to the Acquisition Agreement have been obtained and that no law and no judgment is in effect that prevents, makes illegal or prohibits the consummation of the Acquisition), the End Date shall accordingly be extended to a date that is six months after the End Date; provided further that neither Empire nor AcquisitionCo may terminate the Acquisition Agreement if it (or in the case of AcquisitionCo, Merger Sub) is in breach of any of its covenants or agreements and such breach has caused or resulted in either (A) the failure to satisfy the conditions to the obligations of the terminating party to consummate the Acquisition prior to the End Date or (B) the failure of the closing of the Acquisition to have occurred prior to the End Date. If either AcquisitionCo or Empire terminates the Acquisition Agreement pursuant to this clause and, at the time of such termination, the governmental and regulatory consents and approvals required to be obtained by AcquisitionCo and Empire have not been obtained, or any law or judgment is in effect that prevents, makes illegal or prohibits the consummation of the Acquisition (if, and only if, the applicable law or judgment giving rise to such termination arises in connection with the required governmental and regulatory consents and approvals specified in the Acquisition Agreement) and at the time of such termination the Empire Shareholder Approval has been obtained and the other closing conditions for the benefit of AcquisitionCo shall have been satisfied or waived (except for (1) those conditions that by their nature are to be satisfied at the closing of the Acquisition but which conditions would be satisfied or would be capable of being satisfied if the closing of the Acquisition were the date of such termination or (2) those conditions that have not been satisfied as a result of a breach of the Acquisition Agreement by AcquisitionCo), AcquisitionCo shall pay to Empire a fee of US$65,000,000 in cash;

(ii) if any law or judgment is in effect that prevents, makes illegal or prohibits the consummation of the Merger, and the law or judgment giving rise to such non-satisfaction is permanent (rather than preliminary or temporary) and has become final and non-appealable; provided, however, that the right to terminate the Acquisition Agreement pursuant to this clause shall not be available to any party whose failure to comply with any provision of the Acquisition Agreement has been the cause of, or materially contributed to, either the imposition of such law or judgment or the failure of such law or judgment to be resisted, resolved, lifted or vacated, as applicable. If either AcquisitionCo or Empire terminates the Acquisition Agreement pursuant to this clause (if, and only if, the applicable law or judgment giving rise to such termination arises in connection with the required governmental and regulatory consents and approvals specified in the Acquisition Agreement) and at the time of such termination the Empire Shareholder Approval has been obtained and the other closing conditions for the benefit of AcquisitionCo shall have been satisfied or waived (except for (1) those conditions that by their nature are to be satisfied at the closing of the Acquisition but which conditions would be satisfied or would be capable of being satisfied if the closing of the Acquisition were the date of such termination or (2) those conditions that have not been satisfied as a result of a breach of the Acquisition Agreement by AcquisitionCo), AcquisitionCo shall pay to Empire a fee of US$65,000,000 in cash; or

(iii) the Empire Shareholder Approval is not obtained at a duly convened meeting of Empire’s common stockholders (unless such meeting has been adjourned, in which case at the final adjournment thereof). If (1) (A) the Acquisition Agreement is terminated pursuant to this clause by either AcquisitionCo or Empire, prior to the duly convened meeting of Empire’s shareholders, a Takeover Proposal shall have been publicly disclosed and, as of the duly convened meeting of Empire’s shareholders, such Takeover Proposal shall not have been withdrawn or (B) AcquisitionCo or the Empire terminates the Acquisition Agreement pursuant to the termination right described in paragraph (i) above, prior to such termination a Takeover Proposal shall have been publicly disclosed, and as of such termination the Empire Shareholders Meeting shall not have been held and such Takeover Proposal shall not have been withdrawn or (C) AcquisitionCo terminates the Acquisition Agreement with respect to a breach of or failure by Empire to perform a covenant under the Acquisition Agreement, prior to such termination a Takeover Proposal shall have been publicly disclosed, and as of such termination such Takeover Proposal shall not have been withdrawn and (2) within nine months after the termination of the Acquisition Agreement, Empire shall have entered into a definitive agreement with respect to, or consummated, a Takeover Proposal (except that the applicable percentage in the definition of Takeover Proposal shall be “more than 50%” rather than “20% or more”), Empire shall pay to AcquisitionCo a fee of US$53,000,000 in cash.

Moreover, the Acquisition Agreement may be terminated by Empire if:

(i) Empire’s board of directors has made an Adverse Recommendation Change on the basis of a Superior Proposal or an Intervening Event so long as (1) Empire has complied in all material respects with its obligations under the board recommendation provision of the Acquisition Agreement and (2) Empire prior to or concurrently with such termination (A) solely in the case of a termination due to an Adverse Recommendation Change on the basis of a Superior Proposal, enters into an Empire Acquisition Agreement (as defined in this Prospectus) with respect to such Superior Proposal and (B) pays to AcquisitionCo a fee of US$53,000,000 in cash; provided, however, that Empire shall not have the right to terminate the Acquisition Agreement pursuant to this clause after the Empire Shareholder Approval is obtained at a duly convened meeting of Empire's common stockholders;

(ii) AcquisitionCo or Merger Sub breaches or fails to perform any of its covenants or agreements contained in the Acquisition Agreement, or if any of the representations or warranties of AcquisitionCo or Merger Sub contained in the Acquisition Agreement fails to be true and correct, which breach or failure (A) would give rise to the failure of one of the mutual closing conditions or certain closing conditions for the benefit of Empire and (B) is not reasonably capable of being cured by AcquisitionCo or Merger Sub by the End Date (as it may be extended pursuant to the Acquisition Agreement) or is not cured by AcquisitionCo within 30 days after receiving written notice from Empire of such breach or failure; provided, however, that Empire shall not have the right to terminate the Acquisition Agreement pursuant to this clause if Empire is then in breach of any covenant or agreement contained in the Acquisition Agreement or any representation or warranty of Empire contained in the Acquisition Agreement then fails to be true and correct such that certain closing conditions for the benefit of AcquisitionCo could not then be satisfied. If Empire terminates the Acquisition Agreement pursuant to this clause based on a failure by AcquisitionCo to perform its covenants or agreements under the further actions, regulatory approvals and required actions provision of the Acquisition Agreement and at the time of such termination the Empire Shareholder Approval shall have been obtained and the other closing conditions on behalf of AcquisitionCo shall have been satisfied or waived (except for (1) those conditions that by their nature are to be satisfied at the closing of the Acquisition but which conditions would be satisfied or would be capable of being satisfied if the closing of the Acquisition were the date of such termination or (2) those conditions that have not been satisfied as a result of a breach of the Acquisition Agreement by AcquisitionCo), then AcquisitionCo shall pay to Empire a fee of US$65,000,000 in cash; or

(iii) (A) all of the mutual closing conditions and closing conditions for the benefit of Empire have been satisfied or waived in accordance with the Acquisition Agreement as of the date that the closing of the Acquisition should have been consummated (except for those conditions that by their terms are to be satisfied at the closing of the Acquisition), (B) AcquisitionCo and Merger Sub do not complete the closing of the Acquisition on the day that the closing of the Acquisition should have been consummated, (C) the persons providing the financing to AcquisitionCo refuse, for any reason, to provide the financing in full or any other failure, for any reason, of the financing to be provided in full has occurred and (D) AcquisitionCo and Merger Sub fails to consummate the closing of the Acquisition within five business days following their receipt of written notice from Empire requesting such consummation. If Empire terminates the Acquisition Agreement pursuant to this clause, then AcquisitionCo shall pay to Empire a fee of US$65,000,000 in cash.

Furthermore, the Acquisition Agreement may be terminated by AcquisitionCo if:

(i) the Empire board of directors or a committee thereof has made an Adverse Recommendation Change; provided, however, that AcquisitionCo shall not have the right to terminate the Acquisition Agreement under this clause after the Empire Shareholder Approval is obtained at a duly convened meeting of Empire's shareholders. If the Acquisition Agreement is terminated pursuant to this clause Empire shall pay to AcquisitionCo a fee of US$53,000,000 in cash; or

(ii) if Empire breaches or fails to perform any of its covenants or agreements contained in the Acquisition Agreement, or if any of the representations or warranties of Empire contained in the Acquisition Agreement fails to be true and correct, which breach or failure (A) would give rise to the failure of a mutual closing condition or certain closing conditions for the benefit of AcquisitionCo and (B) is not reasonably capable of being cured by Empire by the End Date (as it may be extended pursuant to the Acquisition Agreement) or is not cured by Empire within 30 days after receiving written notice from AcquisitionCo of such breach or failure; provided, however, that AcquisitionCo shall not have the right to terminate the Acquisition Agreement pursuant to this clause if AcquisitionCo is then in breach of any covenant or agreement contained in the Acquisition Agreement or any representation or warranty of AcquisitionCo contained in the Acquisition Agreement then fails to be true and correct such that certain closing conditions for the benefit of Empire could not then be satisfied.

Payment of Fees and Effect on Termination

The Acquisition Agreement provides that, upon payment of the termination fee by AcquisitionCo to Empire in the circumstances in which AcquisitionCo is obligated to pay such fee, AcquisitionCo and the Guarantor shall have no further liability to Empire with respect to the Acquisition Agreement or the transactions contemplated by the Acquisition Agreement, except that AcquisitionCo shall not be released from any liability for a willful breach (as defined in the Acquisition Agreement) of the Acquisition Agreement. In addition, upon payment of the termination fee by Empire to AcquisitionCo in the circumstances in which Empire is obligated pay such fee, Empire shall have no further liability to AcquisitionCo, Merger Sub, their affiliates or representatives with respect to the Acquisition Agreement or the transactions contemplated by the Acquisition Agreement.

FINANCING THE ACQUISITION

The cash purchase price of the Acquisition and the Acquisition-Related Expenses will be financed at the closing of the Acquisition with a combination of some or all of the following: (i) net proceeds of the first instalment under the Offering; (ii) net proceeds of any subsequent bond or other debt offerings; (iii) amounts drawn under the Acquisition Credit Facilities and the existing revolving credit facilities in favour of Algonquin (the "**Revolving Facilities**"); and, (iv) existing cash on hand and other sources available to the Corporation.

Prior to the closing of the Acquisition, Algonquin (on a consolidated basis) intends to invest in short term interest bearing securities with an investment grade counterparty or reduce amounts outstanding on the Revolving Facilities with the net proceeds of the first instalment under the Offering, which are expected to be $313,000,000 (assuming no exercise of the Over-Allotment Option). In the event Algonquin reduces amounts outstanding on the Revolving Facilities, Algonquin will maintain readily available capacity under the Revolving Facilities, or have cash on hand together with such available capacity, in an amount at least equal to the net proceeds of the first instalment paid on the closing of the Offering (and the exercise of the Over-Allotment Option, if applicable). Upon the closing of the Acquisition, Algonquin (on a consolidated basis) intends to use the net proceeds of the final instalment under the Offering, which are expected to be $647,000,000 (assuming no exercise of the Over-Allotment Option), to reduce amounts outstanding under the Acquisition Credit Facilities concurrently with or following the closing of the Acquisition.

Algonquin expects that with the Offering, the Corporation will have substantially fulfilled its common equity requirement for the closing of the Acquisition (provided the Over-Allotment Option is exercised in full). With respect to any preferred equity and bond or other debt offerings, which may occur prior to or following closing of the Acquisition, Algonquin currently intends to focus on preferred equity and bond or other debt financings, denominated principally in U.S. dollars in order to provide a significant natural currency hedge.

Algonquin's overall financing plan in respect of the Acquisition is structured and targeted to maintain Algonquin's and Empire's current credit ratings profile.

See "Risk Factors" for a discussion of certain risks relating to the financing of the Acquisition.

Acquisition Credit Facilities

For purposes of financing the cash purchase price of the Acquisition, on February 9, 2016, Algonquin obtained commitment letters from Canadian Imperial Bank of Commerce, The Bank of Nova Scotia, JPMorgan Chase Bank, N.A. and Wells Fargo Bank, National Association, respectively, providing for non-revolving syndicated term credit facilities in favour of Algonquin in an aggregate amount of US$1.6 billion (the "**Acquisition**

Credit Facilities"). The Acquisition Credit Facilities consist of (i) a senior unsecured one-year term credit facility (the commitments thereunder, the "**Tranche A Bridge Commitments**"; and the loans thereunder, the "**Tranche A Bridge Loans**") in an aggregate principal amount of up to US$535 million, repayable in full on the first anniversary following its advance, and a (ii) senior unsecured one-year term credit facility (the commitments thereunder, the "**Tranche B Bridge Commitments**" and the loans thereunder, the "**Tranche B Bridge Loans**") in an aggregate principal amount of up to US$1,065 million, repayable in full on the first anniversary following its advance.

Subject to certain prescribed exceptions, Algonquin is required to effect reductions or make prepayments (the "**Commitment Reductions**") of the Acquisition Credit Facilities in an amount equal to the net cash proceeds from the issuance of any indebtedness, common equity, or any other equity (including hybrid equity securities) or any other non-ordinary course asset sales or dispositions by Algonquin or any of its subsidiaries, subject to certain prescribed exceptions and certain other prescribed transactions. Net proceeds from any such offerings, including the net proceeds of the final instalment under the Offering, or from any such issuances or non-ordinary course asset sales or dispositions, will be applied to permanently reduce the commitments of the lenders under the Acquisition Credit Facilities or to repay the Acquisition Credit Facilities after they are drawn. See "Financing the Acquisition".

The credit agreements pursuant to which the Acquisition Credit Facilities will be extended (the "**Acquisition Credit Agreements**") will contain certain prepayment options in favour of Algonquin and certain prepayment obligations (the "**Mandatory Prepayments**") upon the occurrence of certain events. In particular, the net cash proceeds of any equity or debt offering by Algonquin and certain of its subsidiaries (other than certain permitted equity or debt offerings subject to certain prescribed exceptions) and of any non-ordinary course asset sales or dispositions (subject to certain prescribed exceptions) will be required to be used to prepay the Acquisition Credit Facilities and any prepayment under the Acquisition Credit Facilities may not be re-borrowed. The Acquisition Credit Agreements will contain customary representations and warranties and affirmative and negative covenants of Algonquin that will closely resemble those in the Revolving Facilities as the same may be amended to reflect the Acquisition.

As part of these covenants, Algonquin will generally be required to maintain a consolidated debt to consolidated capitalization ratio of not more than 0.75:1.00, to be defined and calculated in a manner consistent with the Revolving Facilities as modified to provide that for purposes of calculating the consolidated debt to consolidated capitalization ratio, consolidated indebtedness shall exclude any non-recourse debt incurred by Algonquin or any of its subsidiaries after the date hereof to finance certain specified projects any equity attributable to any such projects and financed with any such non-recourse debt, provided that, the aggregate amount of such excluded non-recourse debt shall not exceed US$625 million. The consolidated debt to consolidated capitalization ratio shall be subject to a "step-down" to 0.70:100 upon termination of the Tranche A Bridge Commitments and the prepayment of all outstanding Tranche A Bridge Loans. In order for Algonquin to meet certain prescribed exceptions for equity or debt issuances (to the Commitment Reductions and the Mandatory Prepayments) it must be in compliance with the consolidated debt to consolidated capitalization ratio, calculated on a *pro forma* basis.

Customary fees are payable by Algonquin in respect of the Acquisition Credit Facilities and amounts outstanding under the Acquisition Credit Facilities will bear interest at market rates.

CAPITALIZATION

Upon completion of the Offering, the closing of the Acquisition and assuming the payment of the final instalment and the conversion of the Debentures into Common Shares, the Corporation will have an aggregate of approximately 350,514,971 Common Shares outstanding, or approximately 364,665,914 Common Shares if the Over-Allotment Option is exercised in full.

The following table sets out the consolidated capitalization of the Corporation as at September 30, 2015 and on a pro forma basis, as of such date after giving effect to (i) the net proceeds of the Offering (including the payment of both the first instalment and final instalment), assuming no exercise of the Over-Allotment Option, determined after deducting the Underwriters' fee and estimated expenses of the Offering on an after-tax basis, (ii) the Acquisition Credit Facilities to be drawn at the closing of the Acquisition to fund the balance of the purchase price, (iii) the Acquisition, including the assumption of $1,173.8 million (US$879.6 million) of Empire's consolidated debt, (iv) the conversion of the Debentures into Common Shares and (v) the changes in Common Shares and long-term debt from October 1, 2015 up to and including February 12, 2016. See "Changes in Share and Loan Capital Structure" and "Financing the Acquisition". The financial information set out below has been compiled based on financial statements prepared in accordance with U.S. GAAP. See "Index to Financial Statements" and in particular, the pro forma financial statements beginning on page F-84 of this Prospectus.

	As at September 30, 2015 (unaudited)	Pro forma As at September 30, 2015 (unaudited)(1)
	(in millions of $ dollars)	
Total Debt(2)	**1,631.9**	**4,245.5**
Shareholders' equity		
Securities offered hereby		**1,000.0**
Common Shares(3)	**1,654.4**	**1,768.5**
Subscription Receipts(4)	**110.5**	**110.5**
Preferred Shares	**213.8**	**213.8**
Additional contributed surplus	**36.5**	**36.5**
Accumulated other comprehensive loss	**238.1**	**238.1**
Retained earnings	**(524.5)**	**(608.1)**
Non-Controlling Interest(5)	**366.5**	**366.5**
Total capitalization	**3,727.2**	**7,371.3**

(1) After giving effect to (i) the net proceeds of the Offering (including the payment of both the first instalment and final instalment), assuming no exercise of the Over-Allotment Option, determined after deducting the Underwriters' fee and estimated expenses of the Offering on an after-tax basis, (ii) the Acquisition Credit Facilities to be drawn at the closing of the Acquisition to fund the balance of the purchase price, (iii) the Acquisition and the assumption of $1,173.8 million (US$879.6 million) of Empire's consolidated debt, and (iv) the conversion of the Debentures into Common Shares. See "Changes in Share and Loan Capital Structure", "Financing the Acquisition" and "Index to Financial Statements".

(2) Includes long-term debt (including the current portion and short-term borrowings) and Series C Preferred Shares (as defined in this Prospectus). The Series C Preferred Shares are mandatorily redeemable in 2031 and have a contractual cumulative cash dividend paid quarterly until the date of redemption. Such shares are accounted for as liabilities on the Corporation's consolidated financial statements.

(3) Does not include the Common Shares issuable upon the conversion of the Debentures, which are included as "Securities offered hereby".

(4) Includes $77.5 million and $33.0 million in subscription receipts that Emera Inc. purchased in September 2014 and December 2014, respectively, by way of private placements completed in connection with the equity offerings by the Corporation at those times. These subscription receipt offerings were pursuant to the terms of the Strategic Investment Agreement entered into between the Corporation and Emera Inc. on April 29, 2011.

(5) Includes redeemable non-controlling interest in Bakersfield solar facility.

EARNINGS COVERAGE RATIOS

The Corporation's interest requirements on all of its outstanding debt securities after giving effect to the issue of $1 billion principal amount of 5.00% Debentures distributed hereunder amounted to $117.5 million and $121.0 million for the 12 months ended December 31, 2014 and the 12 months ended September 30, 2015, respectively. The Corporation's earnings before interest and income tax for the 12 months ended December 31, 2014 and 12 months ended September 30, 2015 were $150.6 million and $206.2 million, respectively, which is 1.28 times and 1.70 times, respectively, the Corporation's aggregate interest requirements for the periods.

The earnings coverage ratios of the Corporation calculated on a pro forma basis after giving effect to the Acquisition (including the assumption of Empire's consolidated debt), the conversion of the Debentures into

Common Shares, and the Acquisition Credit Facilities to be drawn at the closing of the Acquisition that remain outstanding after the payment of the final instalment, are calculated as follows: (i) the Corporation's interest requirements on all of its outstanding debt securities amounted to $154.0 million and $126.1 million for each of the 12 months ended December 31, 2014 and the nine months ended September 30, 2015, respectively; and (ii) the Corporation's earnings before interest and income tax for the 12 months ended December 31, 2014 and nine months ended September 30, 2015 were $309.2 million and $290.8 million, respectively, which is 2.01 times and 2.31 times, respectively, the Corporation's aggregate interest requirements for the periods.

CHANGES IN SHARE AND LOAN CAPITAL STRUCTURE

The following describes the changes in the share and loan capital structure of Algonquin since September 30, 2015:

(i) During the period from October 1, 2015 up to and including February 12, 2016, Algonquin issued an aggregate of 14,355,000 Common Shares for consideration of approximately $150.0 million, pursuant to an offering of Common Shares under a prospectus supplement to the Corporation's short form base shelf prospectus dated February 18, 2014.

(ii) During the period from October 1, 2015 up to and including February 12, 2016, the Corporation's consolidated long-term debt, including current portions and committed credit facility borrowings classified as long-term debt, increased by approximately $374.0 million, principally due to the following:

  (a) closing of a $313.6 (US$235.0 million) term credit facility by Liberty Utilities on January 4, 2016. The proceeds from the term credit facility were used to partially finance the acquisition of Park Water. The term credit facility matures on July 7, 2017.

  (b) Assumption of $116.8 million (US$87.5 million) of debt as a result of the closing of the Park Water on January 8, 2016.

  This increase was partially offset by:

  (c) repayment in full on October 1, 2015 of all outstanding amounts under the LPSCo Water System's $13.1 million (US$9.8 million) IDA bonds.

  (d) scheduled principal repayment of the amortizing loans, and Series C Preferred Share dividends totalling $1.2 million; and

  (e) net repayment of approximately $43.7 million of borrowings under the three credit facilities available to the Corporation and its subsidiaries. The net change was a result of proceeds from the Corporation's common equity offering completed in December 2015 and funds from operations.

(iii) Assumes non-underwriting expenses of the Offering estimated at approximately $1.6 million.

(iv) As a result of the Offering, after giving effect to the assumed conversion of the Debentures into Common Shares, shareholders' equity in the Corporation will increase by approximately $887 million.

SHARE CAPITAL OF ALGONQUIN

The authorized share capital of the Corporation consists of an unlimited number of Common Shares and an unlimited number of preferred shares issuable in one or more series. As at February 12, 2016, 256,175,348 Common Shares, 4,800,000 cumulative rate reset preferred shares, series A (the "**Series A Shares**"), 100 series C preferred shares ("**Series C Shares**") and 4,000,000 cumulative rate reset preferred shares, Series D (the "**Series D Shares**") of the Corporation were outstanding. The Corporation's Common Shares, Series A Shares and Series D Shares are listed on the TSX under the symbols "AQN", "AQN.PR.A", and "AQN.PR.D", respectively. The Series C Shares are not listed.

PRIOR SALES

During the 12 months preceding the date of this Prospectus, the Corporation issued the following Common Shares and securities convertible into Common Shares:

Share and Option Grants

On May 19, 2015, the Corporation issued 1,608,974 options under its stock option plan at an exercise price of $9.76 per stock option. On August 27, 2015, the Corporation issued 18,551 options under its stock option plan at an exercise price of $9.23 per stock option. Other than these options, the Corporation did not issue any other options during the 12 month period preceding the date of this Prospectus.

Performance Share Unit / Restricted Share Unit Plan

During the 12 month period preceding the date of this Prospectus, the following performance share units and restricted share units were granted (or otherwise accrued under the terms of) the Corporation's Performance/Restricted Share Unit Plan for employees of the Corporation and its participating affiliates.

Three Months Ended	Number of Units Issued
December 2014	3,944
March 2015	6,332
June 2015	186,057
September 2015	8,791
December 2015	11,070

Under the Performance and Restricted Share Unit Plan, the Corporation has the option to pay vested performance and restricted share units in cash, Common Shares purchased on the market or in Common Shares issued from treasury. If vested performance share units or restricted share units are paid in shares, the participant would receive one Common Share for each whole vested performance share unit or restricted share unit.

Directors' Deferred Share Unit Plan

During the 12 month period preceding the date of this Prospectus, the Corporation granted the following deferred share units under its Directors' Deferred Share Unit Plan ("**DSU Plan**") to non-employee directors of the Corporation.

Three Months Ended	Number of Units Issued
December 2014	8,154
March 2015	10,395
June 2015	10,418
September 2015	13,063
December 2015	13,353

Under the DSU Plan, non-employee directors of the Corporation may elect annually to receive all or any portion of their compensation in deferred share units in lieu of cash compensation. The DSU Plan provides for settlement in cash or Common Shares at the election of the Corporation.

Employee Share Purchase Plan

During the 12 month period preceding the date of this Prospectus, the Corporation issued 118,662 Common Shares pursuant to its employee stock purchase plan at a weighted average issue price of $9.78 per Common Share.

Dividend Reinvestment Plan

During the 12 month period preceding the date of this Prospectus, the following number of Common Shares were issued from treasury pursuant to the Corporation's Dividend Reinvestment and Share Purchase Plan (the "**Dividend Reinvestment Plan**") at the average price per Common Share and month indicated below:

Month of Issue	**Number of Shares**	**Price per Share ($)**
January 2015	706,680	9.17
April 2015	619,468	9.14
July 2015	907,017	8.83
October 2015	997,532	8.97
December 2015	292,337	$10.42

Common Share Offering

On December 2, 2015, the Corporation issued 14,355,000 Common Shares at a price of $10.45 per Common Share pursuant to an offering of Common Shares under a prospectus supplement to the Corporation's short form base shelf prospectus dated February 18, 2014.

TRADING PRICES AND VOLUMES

The outstanding Common Shares, Series A Shares and Series D are traded on the TSX under the trading symbol "AQN", "AQN.PR.A" and "AQN.PR.D", respectively. The following table sets forth the high and low price for, and the volume of trading in, the Common Shares, Series A Shares and Series D Shares, respectively, for the periods indicated, based on information obtained from the TSX.

Common Shares

	Price ($)		**Average Daily**
Month	**High**	**Low**	**Trading Volume**
2015			
February	10.51	9.97	348,175
March	10.39	7.50	1,141,069
April	10.10	9.21	552,794
May	9.94	9.43	638,044
June	9.80	8.87	432,733
July	9.77	9.05	400,265
August	9.99	8.59	486,028
September	9.84	9.09	393,551
October	10.30	9.20	643,235
November	10.94	10.03	590,691
December	11.35	10.09	665,399
2016			
January	11.61	10.30	915,320
February 1 - 12	12.01	10.37	1,174,052

Series A Shares

Month	Price ($) High	Low	Average Daily Trading Volume
2015			
February	22.98	21.78	2,145
March	22.15	20.15	5,110
April	21.90	20.19	5,141
May	22.08	21.31	1,868
June	21.86	19.40	2,642
July	20.18	17.99	4,220
August	19.37	17.35	3,109
September	18.52	16.02	5,560
October	19.95	16.14	2,961
November	19.70	17.75	7,437
December	18.60	16.00	4,866
2016			
January	17.55	14.10	3,010
February 1 - 12	15.83	13.80	3,351

Series D Shares

Month	Price ($) High	Low	Average Daily Trading Volume
2015			
February	25.49	24.49	3,280
March	25.41	22.40	3,282
April	25.49	22.62	5,189
May	25.00	24.27	5,545
June	25.00	23.24	3,055
July	24.33	22.44	3,446
August	23.37	19.86	2,473
September	21.51	18.75	2,286
October	22.44	17.95	3,762
November	22.85	20.02	3,643
December	21.69	17.83	7,730
2016			
January	21.55	17.23	1,958
February 1 - 12	26.49	17.23	2,003

DIVIDEND POLICY

Dividends on the Common Shares are declared at the discretion of Algonquin's Board of Directors (the "**Board of Directors**"). The amount of dividends declared for each Common Share for fiscal 2013, 2014 and 2015 were $0.33, $0.37 and US$0.37625, respectively. Algonquin follows a quarterly dividend schedule, subject to subsequent declarations by the Board of Directors each quarter. Effective August 14, 2014, the Board of Directors approved an increase in the annual dividend from Cdn$0.34 to US$0.35, paid quarterly at a rate of US$0.0875 per Common Share. Effective May 7, 2015, the Board of Directors approved an increase in the annual dividend from US$0.35 to US$0.385 per Common Share, paid at a quarterly rate of US$0.09625. The change in the currency of the dividend better aligns Algonquin's Common Share dividend with the currency profile of its underlying operations.

Regular quarterly dividends at the prescribed rate have been paid on all of the Series A Shares and Series D Shares and in accordance with the terms of the Series C Shares.

Algonquin also has a Dividend Reinvestment Plan to enable holders of Common Shares to invest cash dividends paid on Common Shares in additional Common Shares.

DESCRIPTION OF COMMON SHARES

Dividends

Holders of Common Shares are entitled to dividends on a pro rata basis, as and when declared by the Board of Directors. Subject to the rights of the holders of the preferred shares of the Corporation, if any, who are entitled to receive dividends in priority to the holders of the Common Shares, the Board of Directors may declare dividends on the Common Shares to the exclusion of any other class of shares of the Corporation.

Liquidation, Dissolution or Winding-Up

On the liquidation, dissolution or winding-up of Algonquin, holders of Common Shares are entitled to participate rateably in any distribution of assets of Algonquin, subject to the rights of holders of preferred shares of the Corporation if any, who are entitled to receive the assets of the Corporation on such a distribution in priority to the holders of the Common Shares.

Voting Rights

Holders of the Common Shares are entitled to receive notice of and to attend all annual and special meetings of the shareholders of Algonquin, other than separate meetings of holders of any other class or series of shares, and to one vote in respect of each Common Share held at such meetings.

DETAILS OF THE OFFERING

The Offering consists of $1 billion aggregate principal amount of Debentures represented by Instalment Receipts at a price of $1,000 per Debenture, which are being sold by the Selling Debentureholder on an instalment basis. The first instalment of $333 per $1,000 principal amount of Debentures is payable on the Closing Date. The final instalment of $667 per $1,000 principal amount of Debentures is payable following notification to holders of Instalment Receipts (the "**Final Instalment Notice**") that the Corporation has received all regulatory and government approvals required to finalize the Acquisition by AcquisitionCo of Empire and AcquisitionCo and Empire have fulfilled or waived all other outstanding conditions precedent to closing the Acquisition, other than those which by their nature cannot be satisfied until the closing of the Acquisition, in each case as set out in the Acquisition Agreement (collectively, the "**Approval Conditions**"). See "The Acquisition Agreement". The Final Instalment Notice, which must be given by no later than September 8, 2017, will establish a date for payment of the final instalment (the "**Final Instalment Date**"), which shall not be less than 15 days nor more than 90 days following the date of such notice. Payment of the final instalment in full must be received by the Custodian (as defined in this Prospectus) by no later than 3:30 p.m. (Toronto time) on the Final Instalment Date. Holders should make arrangements with the securities broker, trust company or other financial institution through which they hold

Instalment Receipts to pay the final instalment sufficiently in advance of the Final Instalment Date to ensure that such payment is received by the Custodian prior to this deadline.

The Selling Debentureholder

The Selling Debentureholder is a direct wholly-owned subsidiary of Algonquin organized under the CBCA. The Selling Debentureholder will acquire (both of record and beneficially) the Debentures offered pursuant to this Prospectus from Algonquin for the purpose of participating in the Offering.

If the Over-Allotment Option is exercised by the Underwriters, the Selling Debentureholder will acquire the Debentures purchased in the Over-Allotment Option from Algonquin and will sell them to the Underwriters on the terms and conditions set out in the Underwriting Agreement.

Instalment Receipts

The following is a summary of the material attributes and characteristics of the Instalment Receipts representing Debentures and the rights and obligations of holders thereof. This summary does not purport to be complete and is subject to, and is qualified in its entirety by, the terms of the instalment receipt and pledge agreement (the "**Instalment Receipt Agreement**"), to be dated as of the Closing Date, among the Corporation, the Selling Debentureholder, the Underwriters and CST Trust Company in its capacity as custodian and security agent (the "**Custodian**"). Copies of the Instalment Receipt Agreement will be available for inspection at the principal offices of the Custodian in Toronto, Ontario. A prospective purchaser of Debentures represented by Instalment Receipts should carefully review the Instalment Receipt Agreement, a copy of which will also be available on the Corporation's SEDAR profile at www.sedar.com on or about the Closing Date.

Holders of Instalment Receipts will be bound by the terms of the Instalment Receipt Agreement. The Instalment Receipt Agreement will provide that legal title to the Debentures offered hereby will be held by the Custodian following payment of the first instalment and until the Final Instalment Date, provided the final instalment has been fully paid to the Custodian for the benefit of the Selling Debentureholder on or before the Final Instalment Date (and in no case later than 3:30 p.m. (Toronto time) on the Final Instalment Date). The Debentures offered hereby will be pledged to the Selling Debentureholder by the Underwriters (for and on behalf of the purchasers of Debentures represented by Instalment Receipts under the Offering) at the closing of the Offering and the physical certificate or certificates representing the Debentures will be held in the possession of the Custodian, as security agent, on behalf of the Selling Debentureholder, subject to the terms of the Instalment Receipt Agreement.

Prior to payment of the final instalment, beneficial ownership of Debentures will be represented by Instalment Receipts. An Instalment Receipt will evidence, among other things, (i) the fact that the first instalment has been paid in respect of the Debenture represented thereby and (ii) the right of a holder thereof, subject to compliance with the provisions of the Instalment Receipt Agreement, (x) to have the pledge of the Debentures released following the Final Instalment Date provided that payment in full of the final instalment with respect to such Debentures has been received by the Custodian on or prior to such date or (y) if the Debentures are redeemed by the Corporation prior to payment of the final instalment, to receive (after the Custodian pays the final instalment to the Selling Debentureholder on behalf of the holder) $333 per underlying Debenture plus accrued and unpaid interest on such Debenture up to but excluding the redemption date. A holder of an Instalment Receipt will be deemed to have assumed the obligation to pay the final instalment on or before the Final Instalment Date and to have acquired beneficial ownership of the Debenture represented by the Instalment Receipt, subject to the pledge of such Debenture which secures such obligations subject to the terms of the Instalment Receipt Agreement. Subject to the terms of the Instalment Receipt Agreement, a holder of an Instalment Receipt will be further deemed to agree that the foregoing pledge will remain in effect and be binding and effective notwithstanding any transfer of or other dealings with the Instalment Receipt and the rights evidenced or arising thereby.

The Corporation shall as soon as practicable following satisfaction of the Approval Conditions (but no later than September 8, 2017) cause a Final Instalment Notice to be given to holders of Debentures represented by Instalment Receipts (i) confirming that all Approval Conditions have been fulfilled to the satisfaction of the Corporation, (ii) setting the Final Instalment Date (which shall not be less than 15 days nor more than 90 days following the date that such notice is first given) and (iii) advising holders of their ability to exercise the conversion privilege with respect to Debentures represented by their Instalment Receipts concurrently with the payment of the final instalment. See "Details of the Offering – Debentures – Conversion Right". The Selling Debentureholder shall also cause to be issued a press release containing particulars of the Final Instalment Notice. Payment of the final instalment is required regardless of whether a holder receives the Final Instalment Notice, directly or indirectly. The Final Instalment Date may occur up to 90 days following September 8, 2017.

A holder of an Instalment Receipt will be entitled to make payment, in accordance with the provisions of the Instalment Receipt Agreement, of the final instalment at any time following receipt of the Final Instalment Notice and prior to 3:30 p.m. (Toronto time) on the Final Instalment Date. **A holder of Instalment Receipts that fails to pay the final instalment in full by 3:30 p.m. (Toronto time) on the Final Instalment Date (a "Defaulting Holder") will have no further right to pay the final instalment and all rights and privileges of the Defaulting Holder described below under "– Rights and Privileges" shall immediately cease (unless otherwise waived by the Selling Debentureholder).**

Subject to compliance with the provisions of the Instalment Receipt Agreement and timely payment of the final instalment, the Custodian will, as soon as practicable on or after the Final Instalment Date, discharge and release the pledge of the Debentures represented by such Instalment Receipts. At that time, the Debentures (or the Common Shares into which the Debentures may be converted) will be held through the facilities of CDS, and the holder will receive only a customer confirmation of purchase of the Debentures (or, if the conversion privilege is exercised, the underlying Common Shares) from the holder's CDS Participant (as defined in this Prospectus).

The Instalment Receipts representing the Debentures will be issued in "book-entry only" form and must be purchased or transferred through a participant in CDS (a "**CDS Participant**"). The Corporation will cause a global certificate or certificates representing any newly issued Instalment Receipts to be delivered to, and registered in the name of, CDS or its nominee. All rights and obligations of holders of Instalment Receipts must be exercised or performed through, and all notices, payments or other property to which such holders are entitled or obligated will be made or delivered by the holder holding such Instalment Receipts through CDS or the CDS Participants in accordance with the rules and procedures applicable to CDS and such CDS Participants. Each person who acquires Instalment Receipts will only receive a customer confirmation of purchase from the CDS Participant from or through which the Instalment Receipts representing the Debentures are acquired in accordance with the practices and procedures of that registered dealer. The practices of CDS Participants may vary, but generally customer confirmations are issued promptly after execution of a customer order. CDS is responsible for establishing and maintaining book-entry accounts for its CDS Participants having interests in Instalment Receipts. See "– Book-Entry Only System". Because payment of the final instalment will be made by holders of Instalment Receipts through CDS and CDS Participants, it is strongly advised that holders make arrangements with the securities broker, trust company or other financial institution through which they hold Instalment Receipts to pay their final instalment sufficiently in advance of the Final Instalment Date to ensure that such payment is received by the Custodian by no later than 3:30 p.m. (Toronto time) on the Final Instalment Date.

Transfer of Instalment Receipts

Application has been made to list the Instalment Receipts on the facilities of the TSX, subject to the fulfillment of all of the requirements of the TSX. If listing approval is obtained from the TSX, it is anticipated that holders will be able to transfer Instalment Receipts through the facilities of the TSX until the close of trading on the trading day immediately preceding the Final Instalment Date following which, Instalment Receipts will stop trading on the TSX. Upon a transfer of an Instalment Receipt, the transferee will acquire the transferor's rights, subject to the pledge of the Debentures in favour of the Selling Debentureholder, and become subject to the obligations of a holder of Instalment Receipts under the Instalment Receipt Agreement, including the assumption by the transferee of the obligation to pay the final instalment on or before the Final Instalment Date. No transfer of an Instalment Receipt after the Final Instalment Date will be accepted (except where an intermediary holds Instalment Receipts on behalf of a non-registered holder and such non-registered holder has failed to pay the final instalment when due, or with the express consent of the Selling Debentureholder).

Liability of Instalment Receipt Holders

Pursuant to the Instalment Receipt Agreement, the Underwriters will pledge (for and on behalf of the purchasers of Debentures represented by Instalment Receipts under the Offering) the Debentures purchased on an instalment basis to secure payment of the final instalment. If payment of the final instalment is not duly received by the Custodian from a holder of Instalment Receipts when due, the Instalment Receipt Agreement will provide that (except as set out below) any Debenture then remaining pledged under the Instalment Receipt Agreement may, at the option of the Selling Debentureholder, subject to complying with applicable law, be forfeited to the Selling Debentureholder in full satisfaction of the obligations of such holder of Instalment Receipts secured thereby. The Instalment Receipt Agreement will further provide that the Selling Debentureholder may, alternatively, direct the Custodian to sell the Debentures in respect of which payment of the final instalment was not duly received, in accordance with the requirements of applicable law and of the Instalment Receipt Agreement, and remit to the Defaulting Holder of Instalment Receipts its pro rata portion of the proceeds of sale after deducting therefrom the amount of the remaining unpaid final instalment, the amount of any applicable withholding taxes and the Defaulting Holder's pro rata portion of the costs of sale (such costs not to exceed $25 per $1,000 principal amount of Debentures). The Instalment Receipt Agreement will provide that the foregoing shall not limit any other remedies available to the Selling Debentureholder against such Defaulting Holder of the Instalment Receipt in the event proceeds of such sale are insufficient to cover the amount of the final instalment and the costs of sale and accordingly, such holder shall in such circumstances remain liable to the Selling Debentureholder for any such deficiency.

Rights and Privileges

Under the Instalment Receipt Agreement, holders of Instalment Receipts will have the same rights and privileges, and will be subject to the same limitations, as holders of Debentures pursuant to the Indenture (as defined in this Prospectus). In particular, holders of Instalment Receipts will be entitled under arrangements through the Custodian, in the manner set forth in the Instalment Receipt Agreement, to (i) receive interest on the Debentures represented by Instalment Receipts up to and including the Final Instalment Date, after which the interest rate payable on the Debentures will fall to an annual rate of 0% and interest will cease to accrue on the Debentures, (ii) receive the Make-Whole Payment in respect of the Debentures represented thereby if the Final Instalment Date occurs prior to the first anniversary of the Closing Date and provided that a holder of Debentures represented by Instalment Receipts has paid the final instalment on or prior to the Final Instalment Date and (iii) exercise the votes attached to the Debentures represented by such Instalment Receipts. In the event that the Corporation issues (including on liquidation, dissolution or winding-up) to the holders of Debentures any securities, or options, rights or warrants to purchase any securities, or any securities convertible into or exchangeable for securities, or other property or assets of like nature, the Custodian will, as promptly as commercially reasonable sell such securities, options, rights, warrants, evidences of indebtedness, property or assets and remit pro rata to the holders of Instalment Receipts, the proceeds of sale net of the Custodian's costs of disposition, subject to withholding tax requirements.

Redemption of Debentures and Cancellation of Instalment Receipts

In the event that Debentures are required to be redeemed by the Corporation prior to the Final Instalment Date, the Corporation shall, in respect of each Instalment Receipt outstanding on the date of such redemption, pay (or cause to be paid) to the Selling Debentureholder, on behalf of the holder of an Instalment Receipt, an amount equal to the final instalment and pay the balance plus any accrued and unpaid interest to the holder. Payment of such redemption price will be made on the date that the Debentures are redeemed by the Corporation.

Modification

Apart from changes which do not adversely affect in any material respect the holders of Instalment Receipts as a group (which may be made without the consent of such holders), the Instalment Receipt Agreement may not be amended without the affirmative vote of the holders of Instalment Receipts entitled to not less than two-thirds of the principal amount of Debentures represented by Instalment Receipts which are represented and voted at a meeting duly called for the purpose or rendered by instruments in writing signed by the holders of Instalment Receipts representing not less than two-thirds of the principal amount of the Debentures.

General

The Custodian may require holders of Instalment Receipts from time to time to furnish such information and documents as may be necessary or appropriate to comply with any fiscal or other laws or regulations relating to the Debentures or to rights and obligations represented by Instalment Receipts. The Custodian shall not be responsible for any taxes, duties, governmental charges or expenses which are or may become payable in respect of the Debentures or Instalment Receipts. In this regard, the Custodian shall be entitled to deduct or withhold from any payment or other distribution required or contemplated by the Instalment Receipt Agreement the appropriate amount of money or property, or to require holders of Instalment Receipts to make any required payments, and to withhold delivery of certificates representing the Debentures until satisfactory provision for payment is made, in respect of any non-resident Canadian withholding taxes or other taxes, duties or governmental charges or expenses required by applicable law to be withheld or paid.

Holders of Instalment Receipts will not be liable for charges and expenses of the Custodian except for any taxes, duties and other governmental charges which may be payable as described above.

Book-Entry Only System

Registration of interests in and transfers of Instalment Receipts will be made only through the book-entry only system of CDS (the "**Book-Entry Only System**"). Instalment Receipts must be purchased, transferred and surrendered through a CDS Participant. Upon purchase of any Instalment Receipts representing Debentures, the Corporation understands that the holder of Instalment Receipts will receive only a customer confirmation from the registered dealer which is a CDS Participant and from or through which the Instalment Receipts are purchased. References in this Prospectus to a holder of Instalment Receipts mean, unless the context otherwise requires, the owner of the beneficial interest in such Instalment Receipts.

The ability of a beneficial owner of Instalment Receipts to pledge such Instalment Receipts or otherwise take action with respect to such beneficial holder's interest in such Instalment Receipts (other than through a CDS Participant) may be limited due to the lack of a physical certificate.

The Selling Debentureholder has the option to terminate registration of the Instalment Receipts through the Book-Entry Only System in which case certificates for the Instalment Receipts in fully registered form would be issued to holders of such Instalment Receipts.

Debentures

The following is a summary of the material attributes and characteristics of the Debentures. This summary does not purport to be complete and is subject to, and is qualified in its entirety by, the terms of the trust indenture (the "**Indenture**") to be dated on or about the Closing Date between the Corporation, as issuer, and CST Trust Company, as trustee (in such capacity, the "**Trustee**"). A prospective purchaser of Debentures represented by Instalment Receipts should carefully review the Indenture, a copy of which will be available on the Corporation's SEDAR profile at www.sedar.com on or about the Closing Date.

The Debentures will be issued to the Selling Debentureholder on the Closing Date as the initial series under the Indenture and in the aggregate principal amount of $1 billion. In the event that the Over-Allotment Option is exercised, Algonquin will issue additional Debentures of the same series under the Indenture.

The Debentures will be dated as of the Closing Date and will mature on the Maturity Date. The Debentures are issuable in denominations of $1,000 and integral multiples thereof and will bear interest at an annual rate of 5.00% per $1,000 principal amount of Debentures and will be payable quarterly in arrears in equal instalments on the 15th day of March, June, September and December of each year (or the next business day if the 15th falls on a weekend or holiday) to and including the Final Instalment Date. The first interest payment will be made on June 15, 2016 in the amount of $14.5205 per $1,000 principal amount of Debentures and will include interest payable from and including the date of issue. Subsequently, quarterly interest payments will be made in the amount of $12.50 per $1,000 principal amount of Debentures. A final interest payment will be made on the Final Instalment Date and will be equal to the unpaid interest accrued from the date of the last quarterly interest payment to and including the Final Instalment Date. On the day following the Final Instalment Date, the interest rate payable on the Debentures will fall to an annual rate of 0% and interest will cease to accrue on the Debentures. Based on a first instalment of $333 per $1,000 principal amount of Debenture and assuming the Final Instalment Date occurs on or after the first anniversary of the Closing Date, the effective annual yield to and including the Final Instalment Date will be 15.0%, and the effective yield thereafter will be 0%.

If the Final Instalment Date occurs on a day that is prior to the first anniversary of the Closing Date, holders of Debentures who have paid the final instalment on or before the Final Instalment Date will be entitled to receive, on the business day following the Final Instalment Date, in addition to the payment of accrued and unpaid interest to and including the Final Instalment Date, the Make-Whole Payment, being an amount equal to the interest that would have accrued from the day following the Final Instalment Date to and including the first anniversary of the Closing Date had the Debentures remained outstanding and continued to accrue interest until and including such date. No Make-Whole Payment will be payable if the Final Instalment Date occurs on or after the first anniversary of the Closing Date. No Make-Whole Payment will be made in the event that the Corporation redeems the Debentures.

The Debentures will be direct obligations of Algonquin and will not be secured by any mortgage, pledge, hypothec or other charge and will be subordinated to other liabilities of the Corporation as described below under "– Subordination". The Indenture does not restrict the Corporation from incurring additional indebtedness for borrowed money or from mortgaging, pledging or charging its properties to secure any indebtedness.

Payment Upon Maturity

On the Maturity Date, the Corporation will repay the principal amount of any Debentures not converted into Common Shares and remaining outstanding, in cash. The Corporation may, at its option and without prior notice, satisfy the obligation to pay all or a portion of the principal amount of such Debentures on maturity by delivery of that number of freely tradable Common Shares obtained by dividing the aggregate principal amount of the Debentures then outstanding by 95% of the Market Price.

Conversion Right

At the option of the holder and provided that payment of the final instalment has been made, each Debenture will be convertible into Common Shares on or at any time on or after the Final Instalment Date, but prior to the earlier of the date that the Corporation redeems the Debentures or the Maturity Date. The Conversion Price will be $10.60 per Common Share, being a conversion rate of 94.3396 Common Shares per $1,000 principal amount of Debentures, subject to adjustment in certain events. No adjustment will be made for cash dividends on Common Shares issuable upon conversion or for accrued and unpaid interest, which will be paid by the Corporation in cash. A holder of Debentures who does not exercise its conversion privilege concurrently with the payment of the final instalment will hold a Debenture that pays 0% interest and may be redeemed by the Corporation in whole or in part on any trading day following the Final Instalment Date at a price equal to its principal amount plus any unpaid interest which accrued prior to and including the Final Instalment Date.

Subject to the provisions thereof, the Indenture will provide for the adjustment of the Conversion Price in certain events including: (a) the distribution of Common Shares or securities convertible into Common Shares to holders of its Common Shares by way of stock dividend or otherwise, other than an issue of Common Shares to holders of outstanding Common Shares who have elected to receive dividends in stock in lieu of receiving cash dividends paid in the ordinary course; (b) the subdivision or consolidation of the outstanding Common Shares; (c) the issuance of rights or warrants to all holders of Common Shares entitling them to acquire Common Shares or other securities convertible into Common Shares at less than the Conversion Price; (d) the distribution to all holders of Common Shares of any securities or assets (other than cash dividends and dividends in Common Shares); or (e) if an issuer bid or exchange offer is made by the Corporation for its Common Shares. There will be no adjustment of the Conversion Price in respect of any event described herein if, with the prior regulatory approval and the approval of the TSX, the holders of the Debentures are allowed to participate as though they had converted their Debentures prior to such transaction. The Corporation will not be required to make adjustments in the Conversion Price unless the effect of such adjustment would change the Conversion Price by at least 1%, provided that any adjustment of less than 1% will be carried forward and taken into account in connection with any subsequent adjustment.

No fractional Common Shares will be issued on any conversion but in lieu thereof, the Corporation will satisfy such fractional interest by a cash payment equal to the Conversion Price of such fractional interest, provided that the Corporation shall not be required to make any cash payment of less than $10.00.

Redemption

Prior to the Final Instalment Date, the Debentures may not be redeemed by the Corporation, except that the Debentures will be redeemed by the Corporation at a price equal to their principal amount plus accrued and unpaid interest following the earlier of: (i) notification to holders that the Approval Conditions will not be satisfied; (ii) termination of the Acquisition Agreement in accordance with its terms; and (iii) September 11, 2017, if the Final Instalment Notice has not been given on or before September 8, 2017. Upon any such redemption, the redemption proceeds will be paid by the Corporation to the Custodian on behalf of the holders. The Custodian will pay the following for each $1,000 principal amount of Debentures: (i) $333 plus accrued and unpaid interest to the holder of the Instalment Receipt; and (ii) $667 to the Selling Debentureholder on behalf of the holder of the Instalment Receipt in satisfaction of the final instalment. Under the terms of the Instalment Receipt Agreement, Algonquin has agreed that until such time as the Debentures have been redeemed in accordance with the foregoing or the Final Instalment Date has occurred, the Corporation will maintain readily available capacity under the Revolving Facilities, or have cash on hand together with such available capacity, in an amount at least equal to the net proceeds of the first instalment paid on the closing of the Offering (and on the closing of the Over-Allotment Option, if applicable).

In addition, after the Final Instalment Date, any Debentures not converted to Common Shares may be redeemed by the Corporation at a price equal to their principal amount plus any unpaid interest which accrued prior to the Final Instalment Date.

Subordination

The Debentures will be direct unsecured obligations of Algonquin. Payment of the principal of, interest on, the Make-Whole Payment, if any, and other amounts owing in respect of each Debenture will be subordinated in right of payment to all present and future liabilities of the Corporation for (i) moneys borrowed or raised by whatever means (including, without limitation, by means of commercial paper, bankers acceptances, debt instruments and any liability represented by bonds, debentures, notes or similar instruments), (ii) the deferred purchase price of assets or services or (iii) any trade debts in effect at any time and from time to time (collectively, the "**Senior Indebtedness**"). Payment of the principal of, interest on, the Make-Whole Payment, if any, and other amounts owing in respect of each Debenture will rank pari passu with each other Debenture issued under the Indenture regardless of their actual date or terms of issue, and with all other present and future unsecured and subordinated indebtedness of Algonquin except as prescribed by law.

The Indenture does not limit the ability of the Corporation to incur additional indebtedness, including indebtedness that ranks senior to the Debentures or from mortgaging, pledging, charging, hypothecating, granting a security interest in or otherwise encumbering any or all of its properties to secure any indebtedness. The Indenture provides that the Corporation shall not make any payment, and the holders of Debentures shall not be entitled to demand, accelerate, institute proceedings for the collection of, or receive any payment or benefit (including, without limitation, by set-off, combination of accounts or realization of security or otherwise in any manner whatsoever) on account of indebtedness represented by the Debentures (i) in a manner inconsistent with the terms (as they exist on the date of issue) of the Debentures; (ii) unless all payments of interest then due or payable on all Senior Indebtedness for borrowed money have been made; (iii) at any time when any amount is in arrears under any Senior Indebtedness or an event of default has occurred under Senior Indebtedness, and such a default or event of default is continuing, unless and until such Senior Indebtedness has been paid and satisfied in full or such default or event of default shall have been cured or waived in writing in accordance with the provisions of such Senior Indebtedness; or (iv) if the making of any such payment or the taking of any such action would create, including by the lapse of time or giving of notice, a default or an event of default under any Senior Indebtedness unless and until such Senior Indebtedness has been satisfied in full or the making of any such payment or taking of any such action would no longer create, including by lapse of time or giving of notice, a default or an event of default under any Senior Indebtedness.

In addition, the Trustee on behalf of the holders of Debentures may, at the request of the Corporation, enter into contractual subordination agreements with certain lenders of the Corporation with terms to the foregoing effect.

Events of Default

The Indenture will include the following events of default:

(a) failure to pay any principal or premium, if any, on the Debentures, when the same becomes due and payable whether on maturity, redemption, acceleration or otherwise, which default continues for a period of five business days;

(b) failure to pay any interest or Make-Whole Payment, if any, on the Debentures, which default continues for 30 days after the date when due;

(c) failure to deliver when due all cash and Common Shares deliverable upon conversion of the Debentures, which failure continues for 30 days;

(d) the Corporation's failure to perform or observe any other material term, covenant or agreement contained in the Debentures or contained in the Indenture for a period of 30 days after receipt of notice of default specifying such failure;

(e) default by the Corporation or any "material subsidiary" (as defined in the Indenture), with respect to any indebtedness (excluding amounts due to the holders of Debentures), where the aggregate principal amount of such indebtedness exceeds an amount equal to the greater of 2% of the consolidated net worth of the Corporation or $50,000,000 at such time and (i) if the default is a payment default, such default continues to exist for a period exceeding 30 days; provided that if the payment obligation to which the default relates is accelerated, then the default shall constitute an event of default immediately following such acceleration, and (ii) if the default is not a payment default, then as a result of the default and the passing of any applicable cure period, the maturity of the obligation is accelerated; provided that, in each case, if the default is cured prior to acceleration of the Debentures, then the event of default shall be deemed to have been cured; and

(f) certain events of bankruptcy, insolvency or reorganization affecting the Corporation.

If an event of default shall occurs and is continuing, either the Trustee or the holders of at least 25% in aggregate principal amount of the Debentures then outstanding may declare (by notice to the Corporation and the Trustee) the principal of the Debentures and any accrued and unpaid interest, if any, through the date of such declaration to be immediately due and payable. In the case of certain events of bankruptcy or insolvency, the principal amount of the Debentures together with any accrued but unpaid interest, if any, through the occurrence of such event shall automatically become and be immediately due and payable.

Modification

The rights of the holders of the Debentures may be modified. For that purpose, among others, the Indenture will contain certain provisions which will make binding on all holders of Debentures resolutions passed at meetings of the holders of Debentures by votes cast thereat by holders of not less than two-thirds of the principal amount of the Debentures, or rendered by instruments in writing signed by the holders of not less than two-thirds of the principal amount of the Debentures then outstanding.

Certification and the Book-Entry Only System

Registration of interests in and transfers of Debentures represented by Instalment Receipts will be made only through the Book-Entry Only System. Debentures represented by Instalment Receipts must be purchased, transferred and surrendered through a CDS Participant. From the Closing Date to the Final Instalment Date, the Debentures will be issued in certificated and fully registered form in the name of CST Trust Company, in its capacity as security agent under the Instalment Receipt Agreement. Promptly following 3:30 p.m. (Toronto time) on the Final Instalment Date, provided due payment of the final instalment has been made in accordance with the terms of the Instalment Receipt Agreement, the Selling Debentureholder will cause the Custodian to deliver to CDS (i) a global certificate representing those Debentures not converted to Common Shares by exercise of the conversion right and (ii) Common Shares issued upon conversion of Debentures, in each case, to be registered in the name of CDS or its nominee. The Debentures will be represented by one or more global certificates. Thereafter, registration of interests in and transfers of the Debentures will be made only through the depository service of CDS and transfers of Common Shares will be effected electronically through the non-certificated inventory system administered by CDS.

Upon purchase of any Debentures through the Book-Entry Only System, the Corporation understands that the holder of Debentures will receive only a customer confirmation from the registered dealer which is a CDS Participant and from or through which the Debentures are purchased. References in this Prospectus to a holder of Debentures mean, unless the context otherwise requires, the owner of the beneficial interest in such Debentures.

The Corporation will have the option to terminate registration of the Debentures through the Book-Entry Only System, in which case certificates for the Debentures in fully registered form would be issued to holders of such Debentures.

USE OF PROCEEDS

The net proceeds from the Offering (including both the first instalment and final instalment) will be, in the aggregate, $958,400,000, determined after deducting the Underwriters' fee and the estimated expenses of the Offering. In the event that the Over-Allotment Option is exercised in full, the net proceeds will be, in the aggregate, $1,102,400,000. The net proceeds of the Offering will be used directly or indirectly to finance the cash purchase price for the Acquisition and the Acquisition-Related Expenses.

Prior to the closing of the Acquisition, the net proceeds of the first instalment, which are expected to be $313,000,000 (assuming no exercise of the Over-Allotment Option), will initially be utilized to (a) reduce amounts outstanding on the Revolving Facilities or (b) invest in short-term interest bearing securities with investment grade counterparties. In the event the net proceeds of the first instalment are used to reduce outstanding indebtedness, Algonquin will maintain readily available capacity under the Revolving Facilities (or have cash on hand together with such available capacity, in an amount at least equal to the net proceeds of the first instalment paid on the closing of the Offering (and on the closing of the Over-Allotment Option, if applicable). Upon the closing of the Acquisition, Algonquin intends to re-borrow on the Revolving Facilities the amount received from the first instalment under the Offering to finance, directly or indirectly, part of the purchase price payable for the Acquisition (including Acquisition-Related Expenses). Algonquin intends to use the net proceeds of the final instalment under the Offering, which are expected to be $647,000,000 (assuming no exercise of the Over-Allotment Option), together with the net proceeds of the first instalment, to finance, directly or indirectly, part of the purchase price payable for the Acquisition and for other Acquisition-related expenses. See "Relationship between Algonquin, the Selling Debentureholder and Certain Underwriters" and "Financing the Acquisition".

PLAN OF DISTRIBUTION

Pursuant to an underwriting agreement dated February 15, 2016 (the "**Underwriting Agreement**") among Algonquin, the Selling Debentureholder and the Underwriters, the Selling Debentureholder has agreed to sell, and the Underwriters have agreed to purchase, as principals, on the Closing Date, all but not less than all of the Debentures offered hereby on an instalment basis at a price of $1,000 per $1,000 principal amount of Debentures (the "**Offering Price**"). The Offering Price is payable in cash to the Selling Debentureholder on delivery as follows: the first instalment of $333 per $1,000 principal amount of Debenture is payable on the Closing Date against delivery; and the final instalment of $667 per $1,000 principal amount of Debenture is payable on or before the Final Instalment Date. See "Details of the Offering".

The obligations of the Underwriters under the Underwriting Agreement are several and not joint or joint and several and may be terminated by them on the basis of certain stated events. Under the Underwriting Agreement, the obligations of any Underwriter may be terminated in their discretion if, at or prior to the Closing Date: (a) there should occur or commence, or be announced or threatened, any inquiry, action, suit, investigation or other proceeding (whether formal or informal) other than any inquiry, action, suit, investigation or other proceeding based on alleged activities of the Underwriters, or any order is issued by any governmental authority, other than an order based on the alleged activities of the Underwriters, or any law or regulation is promulgated, changed or announced, which, in the reasonable opinion of the Underwriters (or any of them), is expected to prevent or materially restrict the trading in or the distribution of the Debentures, the Instalment Receipts representing the Debentures, the underlying Common Shares or any other securities of the Corporation or would be expected to have a material adverse effect on the market price or value of the Debentures, the Instalment Receipts representing the Debentures, the underlying Common Shares or any other securities of the Corporation; (b) there should develop, occur or come into effect or existence any event, action, state, condition or occurrence of national or international consequence, acts of hostilities or escalation thereof or other calamity or crisis or any change or development involving a prospective change in national or international political, financial or economic conditions, or any law, action, regulation or other occurrence of any nature whatsoever which, in the reasonable opinion of the Underwriters (or any of them), materially adversely affects or involves, or is expected to materially adversely affect or involve, North American financial markets generally or the business, affairs or operations of the Corporation; (c) there should occur any material change (financial or otherwise) in the business, affairs or operations of the Corporation or any change in any material fact (other than a change related solely to the Underwriters), or the Underwriters (or any one of them) become aware of any undisclosed material information, which, in the reasonable opinion of the Underwriters (or any of them), could be expected to have a material adverse effect on the market price or value of the Debentures, the Instalment Receipts representing the Debentures, the Common Shares or any other securities of the Corporation; or (d) the Acquisition Agreement is terminated prior to 8:00 a.m. (Toronto time) on the Closing Date.

The Underwriters are obligated to take up and pay for all of the Debentures represented by Instalment Receipts offered hereby (other than the Debentures represented by Instalment Receipts issuable on exercise of the Over-Allotment Option) if any of those Debentures are purchased under the Underwriting Agreement. The Debentures represented by Instalment Receipts offered hereby are to be taken up by the Underwriters, if at all, on or before a date not later than 42 days after the date of the receipt for the final short form prospectus relating to the Offering.

The Selling Debentureholder has granted to the Underwriters the Over-Allotment Option, which is exercisable in whole or in part at any time prior to the 30th day following the Closing Date and pursuant to which the Underwriters may purchase additional Debentures represented by Instalment Receipts equal to up to 15% of the aggregate principal amount of Debentures represented by Instalment Receipts sold in the Offering on the same terms as set forth above, to cover over-allotments, if any. This Prospectus qualifies the grant of the Over-Allotment Option and the issuance of Debentures represented by Instalment Receipts on the exercise of the Over-Allotment Option. A purchaser who acquires Debentures represented by Instalment Receipts forming part of the Underwriters' over-allocation position acquires those Debentures under this Prospectus, regardless of whether the over-allocation position is ultimately filled through the exercise of the Over-Allotment Option or secondary market purchases.

The Underwriting Agreement provides that the Underwriters will be paid a fee by Algonquin equal to 4.00% of the gross proceeds of the Offering ($40.00 per Debenture) in consideration for their services in connection with the Offering. One-half of the fee is payable on the Closing Date and the remaining one-half is payable on the Final Instalment Date. Accordingly, upon payment of the final instalment and assuming the final instalment payment is made for all outstanding Instalment Receipts, the total price to the public will be $1,000,000,000, the Underwriters' fee will be $40,000,000 and the net proceeds will be approximately $958,400,000, after deducting the expenses of the Offering estimated at $1,600,000. After the Underwriters have made reasonable efforts to sell all the Debentures represented by Instalment Receipts at the Offering Price, the Offering Price may be decreased and may be further changed from time to time to an amount not greater than that set out on the cover page, and the compensation realized by the Underwriters will be decreased by the amount that the aggregate price paid by purchasers for the Debentures represented by Instalment Receipts is less than the gross proceeds paid by the Underwriters to the Selling Debentureholder. The Offering Price and other terms of the Offering were determined by negotiation between the Corporation, the Selling Debentureholder and the Underwriters.

There is currently no market through which the Debentures represented by Instalment Receipts may be sold and purchasers may not be able to resell securities purchased under this Prospectus. This may affect the pricing of the Securities in the secondary market, the transparency and availability of trading prices, the liquidity of the Securities and the extent of issuer regulation. The Corporation has applied to list the Instalment Receipts (representing the Debentures) and the Common Shares issuable on the conversion of the Debentures on the TSX. Listing will be subject to the Corporation fulfilling all of the requirements of the TSX. The Corporation has no current intention to list the Debentures for trading on any exchange, as it currently anticipates all Debentures will be converted to Common Shares on the Final Instalment Date.

Once listed, the Instalment Receipts (representing the Debentures) will be quoted and traded on the TSX in the same manner as other debentures listed on the TSX, with all bids and offers for and trades of Instalment Receipts reflecting only the partly paid capital portion of the Debentures and not accrued interest. Accrued interest will be reflected in the settlement amount and in the confirmations generated by the CDS Participant from or through whom the trade was executed. Bid, offer and trading prices for the Instalment Receipts listed on the TSX will be expressed as a percentage of the $1,000 principal amount of a fully paid Debenture (and not as a percentage of the $333 first instalment already paid). In accordance with TSX trading rules, the Instalment Receipts will be quoted based on $100 principal amounts and all trades in Instalment Receipts will be made in multiples of $1,000. A board lot of Instalment Receipts is represented by one Instalment Receipt, the underlying value of which is $1,000 principal amount of a fully paid Debenture.

Pursuant to rules and policy statements of certain Canadian securities regulators, the Underwriters may not, at any time during the period ending on the date the selling process for the Debentures represented by Instalment Receipts ends and all stabilization arrangements relating to the Debentures represented by Instalment Receipts are terminated, bid for or purchase Instalment Receipts, Debentures or Common Shares. The foregoing restrictions are subject to certain exceptions including: (i) a bid for or purchase made through the facilities of the TSX, in accordance with the Universal Market Integrity Rules of the Investment Industry Regulatory Organization of Canada; (ii) a bid or purchase on behalf of a client, other than certain prescribed clients, provided that the client's order was not solicited by the Underwriter, or if the client's order was solicited, the solicitation occurred before the commencement of a prescribed restricted period; and (iii) a bid or purchase to cover a short position entered into prior to the commencement of a prescribed restricted period. The Underwriters may engage in market stabilization or market balancing activities on the TSX where the bid for or purchase of the Instalment Receipts, Debentures or Common Shares is for the purpose of maintaining a fair and orderly market in the Instalment Receipts, Debentures or Common Shares, subject to price limitations applicable to such bids or purchases. Such transactions, if commenced, may be discontinued at any time.

The securities offered pursuant to this Prospectus may not be offered or sold in the United States. The Debentures, the Instalment Receipts representing the Debentures, and the Common Shares into which the Debentures may be converted have not been, and will not be, registered under the United States Securities Act of 1933, as amended (the "**1933 Act**") or any state securities laws and, may not be offered, or delivered, directly or indirectly, or sold in the United States. The Underwriters have agreed that they will not sell the Debentures represented by Instalment Receipts within the United States. When used in this section, the term "United States" has the meaning ascribed to it in Regulation S under the 1933 Act.

RELATIONSHIP BETWEEN ALGONQUIN, THE SELLING DEBENTUREHOLDER AND CERTAIN UNDERWRITERS

Each of CIBC World Markets Inc., BMO Nesbitt Burns Inc., National Bank Financial Inc., RBC Dominion Securities Inc., TD Securities Inc., Desjardins Securities Inc., J.P. Morgan Securities Canada Inc. and Wells Fargo Securities Canada, Ltd. is an affiliate of a financial institution that has, either solely or as a member of a syndicate of financial institutions, extended (or will extend) credit facilities to, or holds (or will hold) other indebtedness of, the Corporation and/or its subsidiaries, including the Revolving Facilities and the Acquisition Credit Facilities (the "**Bank Indebtedness**"). See "Financing the Acquisition". In connection with the Acquisition, Algonquin engaged Wells Fargo Securities, LLC as lead merger advisor, and J.P. Morgan Securities LLC as lead financial and strategic advisor. Consequently, the Corporation and/or the Selling Debentureholder may be considered a "connected issuer" of these Underwriters within the meaning of applicable securities legislation.

None of these Underwriters will receive any direct benefit from the Offering other than the underwriting commission relating to the Offering. The decision to distribute the Debentures hereunder and the determination of the terms of the Offering were made through negotiation between the Corporation, the Selling Debentureholder and the Underwriters. No bank had any involvement in such decision or determination. As at February 12, 2016, an aggregate of approximately $443.9 million was outstanding under the Bank Indebtedness, which is unsecured. Algonquin and/or its subsidiaries are in material compliance with their respective obligations under the Bank

Indebtedness. Since entering into the Bank Indebtedness, no breach thereunder has been waived by the lenders thereof; and there has been no material change in the financial position of Algonquin or its subsidiaries, except as otherwise described in this Prospectus (including in the documents incorporated herein by reference). Algonquin (on a consolidated basis) intends to use the net proceeds of the final instalment under the Offering to reduce amounts outstanding under the Acquisition Credit Facilities concurrently with or following the closing of the Acquisition. See "Use of Proceeds".

CERTAIN CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

In the opinion of Blake, Cassels & Graydon LLP, counsel to Algonquin and the Selling Debentureholder, and Bennett Jones LLP, counsel to the Underwriters, (collectively, "**Counsel**") the following summary describes the principal Canadian federal income tax considerations generally applicable to a holder who acquires Debentures represented by Instalment Receipts as beneficial owner pursuant to the Offering and who, for the purposes of the application of the Tax Act and at all relevant times: (i) is resident, or is deemed to be resident, in Canada; (ii) holds the Debentures and will hold any Common Shares received on the conversion or maturity of the Debentures (collectively, the "**Securities**") as capital property; (iii) deals at arm's length with Algonquin, the Selling Debentureholder and the Underwriters; and (iv) is not affiliated with Algonquin or the Selling Debentureholder (a "**Holder**"). Generally, the Securities will be capital property to a Holder provided the Holder does not acquire or hold the Securities in the course of carrying on a business or as part of an adventure or concern in the nature of trade. Certain Holders who might not otherwise be considered to hold their Securities as capital property may, in certain circumstances, be entitled to have the Securities, and all other "Canadian securities" (as defined in the Tax Act) owned by such holders in the taxation year of the election and all subsequent taxation years, deemed to be capital property by making the irrevocable election permitted by subsection 39(4) of the Tax Act. Holders are advised to consult their personal tax advisors to determine whether such an election is available and desirable in their particular circumstances.

This summary is not applicable to a Holder: (i) that is a "financial institution", as defined in the Tax Act for the purposes of the mark-to-market rules; (ii) that is a "specified financial institution" as defined in the Tax Act; (iii) an interest which would be a "tax shelter investment" as defined in the Tax Act; (iv) that reports its "Canadian tax results", as defined in the Tax Act, in a currency other than Canadian currency; (v) that enters into a "derivative forward agreement", as defined in the Tax Act, in respect of the Debentures or Common Shares; or (vi) that is a corporation and is, immediately after the acquisition of Common Shares, or becomes as part of a transaction or event or series of transactions or events that includes the acquisition of Common Shares, controlled by a non-resident corporation for purposes of the foreign affiliate dumping rules in section 212.3 of the Tax Act. Any such Holder should consult its own tax advisor with respect to an investment in the Securities.

This summary is based upon the provisions of the Tax Act in force as of the date hereof, all specific proposals to amend the Tax Act that have been publicly announced prior to the date hereof (the "**Proposed Amendments**") and Counsel's understanding of the current published administrative policies and assessing practices of the Canada Revenue Agency. This summary assumes that the Proposed Amendments will be enacted in the form proposed; however, no assurance can be given that the Proposed Amendments will be enacted in the form proposed, if at all. This summary is not exhaustive of all possible Canadian federal income tax considerations and, except for the Proposed Amendments, does not take into account any changes in the law or administrative policies and assessing practices, whether by legislative, governmental or judicial action, nor does it take into account provincial, territorial or foreign tax considerations, which may differ from those discussed herein.

This summary is of a general nature only and is not intended to be, nor should it be construed to be, legal or tax advice to any particular Holder, and no representations with respect to the income tax consequences to any Holder are made. Consequently, prospective Holders should consult their own tax advisors for advice with respect to the tax consequences to them of acquiring Securities pursuant to the Offering, having regard to their particular circumstances. This summary does not address any tax considerations applicable to persons other than Holders and such persons should consult their own tax advisors regarding the consequences of acquiring, holding and disposing of Securities under the Tax Act and any jurisdiction in which they may be subject to tax.

Taxation of Interest on Debentures

A Holder of Debentures represented by Instalment Receipts that is a corporation, partnership, unit trust or any trust of which a corporation or a partnership is a beneficiary will be required to include in computing its income for a taxation year any interest on the Debentures that accrues, or is deemed to accrue, to such Holder to the end of the particular taxation year or that has become receivable by or is received by the Holder before the end of that taxation year, including on a conversion, redemption or repayment at maturity, except to the extent that such interest was included in computing the Holder's income for a preceding taxation year. A "Canadian-controlled private corporation" (as defined in the Tax Act) also may be liable to pay a refundable tax on certain investment income, including interest.

Any other Holder, including an individual, will be required to include in computing income for a taxation year all interest on the Debentures that is received or receivable by the Holder in that taxation year (depending upon the method regularly followed by the Holder in computing income), including on a conversion, redemption or repayment at maturity, except to the extent that the interest was included in the Holder's income for a preceding taxation year. In addition, if at any time a Debenture should become an "investment contract" (as defined in the Tax Act) in relation to a Holder of such Debenture, such Holder will be required to include in computing income for a taxation year any interest that accrues to the Holder on the Debenture up to the end of any "anniversary day" (as defined in the Tax Act) in that year to the extent such interest was not otherwise included in computing the Holder's income for that year or a preceding year.

Any Make-Whole Payment will be deemed to be interest received by the Holder at the time of such Make-Whole Payment and will be required to be included in the Holder's income as described above, to the extent that such Make-Whole Payment can reasonably be considered to relate to, and does not exceed the value at the time of such Make-Whole Payment of, the interest that would have been paid or payable on the Debenture for a taxation year ending after the time of such Make-Whole Payment had the Final Instalment Date not occurred on a day that is prior to the first anniversary of the Closing Date.

Exercise of Conversion Privilege

Generally, a Holder who converts a Debenture into Common Shares pursuant to the conversion privilege will be deemed not to have disposed of the Debenture (except for purposes of the deduction for interest included in income but not received as discussed below under "– Disposition of Debentures"). Accordingly, a Holder who converts a Debenture into Common Shares will not be considered to realize a capital gain (or capital loss) on such conversion. Under the current administrative policy of the Canada Revenue Agency, a Holder who, upon conversion of a Debenture, receives cash not in excess of $200 in lieu of a fraction of a Common Share may either treat this amount as proceeds of disposition of a portion of the Debenture, thereby realizing a capital gain (or capital loss), or reduce the adjusted cost base of the Common Shares that the Holder receives on the conversion by the amount of the cash received.

The aggregate cost to a Holder of Common Shares acquired on the conversion of a Debenture will generally be equal to the Holder's adjusted cost base of the Debenture immediately before the conversion, minus any reduction in respect of fractional Common Shares as described above. For the purposes of determining the adjusted cost base to a Holder of Common Shares at any time, the cost of such Common Shares will be averaged with the adjusted cost base of any other Common Shares owned by the Holder as capital property at the time.

Disposition of Debentures

A disposition or deemed disposition of a Debenture by a Holder, including (whether represented or not by an Instalment Receipt) upon redemption or at maturity but not including the conversion of a Debenture into Common Shares pursuant to the Holder's right of conversion as described above, will generally result in the Holder realizing a capital gain (or a capital loss) equal to the amount by which the proceeds of disposition (adjusted as described below) are greater (or less) than the aggregate of the Holder's adjusted cost base thereof and any reasonable costs of disposition. Such capital gain (or capital loss) will be subject to the tax treatment described below under "– Taxation of Capital Gains and Capital Losses". In this regard, the cost to a Holder of a Debenture represented by an Instalment Receipt will include all amounts paid or payable by the Holder for such Debenture, including the amount of the final instalment, whether paid or unpaid. The proceeds of disposition to a Holder who disposes of a Debenture represented by an Instalment Receipt will include the amount of any unpaid final instalment.

Upon an assignment or other transfer (not including upon redemption or maturity), interest accrued on the Debenture to the date of such transfer will be included in computing the Holder's income for the year of the transfer, except to the extent that it was included in computing the Holder's income for that or a preceding taxation year, and will be excluded from the Holder's proceeds of disposition of the Debenture. Where a Holder has disposed of a Debenture for consideration equal to its fair market value, the Holder will be entitled to deduct in computing income for the year of disposition any amount that has been included in the Holder's income as interest in respect of such Debenture for that year or any preceding taxation year to the extent such amount exceeds the amount received or receivable by the Holder in respect thereof. A conversion of a Debenture into Common Shares is a disposition for purposes of the previous sentence.

If the Corporation pays the principal amount of the Debentures upon maturity by issuing Common Shares to the Holder, the Holder's proceeds of disposition of the Debenture will be equal to the fair market value, at the time of disposition of the Debenture, of the Common Shares and any other consideration so received (except any consideration received in satisfaction of interest, if any). The Holder's aggregate cost of the Common Shares so received will be equal to the fair market value of such Common Shares. For the purposes of determining the adjusted cost base to a Holder of the Common Shares at any time, the cost of such Common Shares will be averaged with the adjusted cost base of any other Common Shares owned by the Holder as capital property at that time.

Where a Debenture represented by an Instalment Receipt is forfeited to the Selling Debentureholder or is sold by the Custodian as a consequence of the Holder's failure to pay the final instalment, the Holder may be subject to special rules in the Tax Act relating to the seizure by a seller of property previously sold or the settlement or forgiveness of debt. Holders should consult their own tax advisors with respect to these special rules.

Dividends on Common Shares

A Holder will be required to include in computing its income for a taxation year any dividends received (or deemed to be received) on the Common Shares. In the case of a Holder that is an individual (other than certain trusts), such dividends will be subject to the gross-up and dividend tax credit rules applicable to taxable dividends received from "taxable Canadian corporations" (as defined in the Tax Act), including the enhanced gross-up and dividend tax credit applicable to any "eligible dividends".

A dividend will be an eligible dividend if the recipient receives written notice (which may include a notice published on the Corporation's website) from the Corporation designating the dividend as an "eligible dividend". There may be limitations on the ability of the Corporation to designate dividends as eligible dividends.

Taxable dividends received by an individual (including certain trusts) may give rise to a liability for alternative minimum tax as calculated under the detailed rules set out in the Tax Act.

A dividend received (or deemed to be received) on the Common Shares by a Holder that is a corporation will generally be deductible in computing the corporation's taxable income. In certain circumstances, subsection 55(2) of the Tax Act (as proposed to be amended by Proposed Amendments released on July 31, 2015) will treat a taxable dividend received by a Holder that is a corporation as proceeds of disposition or a capital gain. Holders that are corporations should consult their own tax advisors having regard to their own circumstances.

A Holder that is a "private corporation", as defined in the Tax Act, or any other corporation controlled, whether because of a beneficial interest in one or more trusts or otherwise, by or for the benefit of an individual (other than a trust) or a related group of individuals (other than trusts), will generally be liable to pay a refundable tax under Part IV of the Tax Act on dividends received (or deemed to be received) on the Common Shares to the extent such dividends are deductible in computing the Holder's taxable income for the taxation year.

Disposition of Common Shares

Generally, on a disposition or deemed disposition of a Common Share, a Holder will realize a capital gain (or capital loss) equal to the amount, if any, by which the proceeds of disposition, net of any reasonable costs of disposition, exceed (or are less than) the adjusted cost base to the Holder of the Common Share immediately before the disposition or deemed disposition. Such capital gain (or capital loss) will be subject to the tax treatment described below under "– Taxation of Capital Gains and Capital Losses".

Taxation of Capital Gains and Capital Losses

Generally, a Holder is required to include in computing its income for a taxation year one-half of the amount of any capital gain (a "**taxable capital gain**") realized in the year. Subject to and in accordance with the provisions of the Tax Act, a Holder is required to deduct one-half of the amount of any capital loss (an "**allowable capital loss**") realized in a taxation year from taxable capital gains realized by the Holder in the year and allowable capital losses in excess of taxable capital gains for the year may be carried back and deducted in any of the three preceding taxation years or carried forward and deducted in any subsequent taxation year against net taxable capital gains realized in such years.

Capital gains realized by an individual (including certain trusts) may give rise to a liability for alternative minimum tax as calculated under the detailed rules set out in the Tax Act.

A "Canadian-controlled private corporation" (as defined in the Tax Act) also may be liable to pay a refundable tax on certain investment income including taxable capital gains.

The amount of any capital loss realized by a Holder that is a corporation on the disposition of a Common Share may be reduced by the amount of dividends received or deemed to be received by it on such Common Share to the extent and under the circumstances prescribed by the Tax Act. Similar rules may apply where a Common Share is owned by a partnership or trust of which a corporation, trust or partnership is a member or beneficiary. Such Holders should consult their own tax advisors.

RISK FACTORS

An investment in: (i) the Debentures represented by Instalment Receipts pending payment of the final instalment; (ii) the Debentures following payment of the final instalment; and (iii) the Common Shares issuable upon the conversion of the Debentures, involves certain risks. A prospective purchaser of Debentures should carefully consider the risk factors and other risks relating to Algonquin's business as described in Algonquin's documents incorporated by reference in this Prospectus, including under:

(a) the heading "Enterprise Risk Management" at pages 52 to 68 in the AIF;

(b) the heading "Enterprise Risk Management" at pages 46 to 57 in the Annual MD&A; and

(c) the heading "Enterprise Risk Management" at pages 37 to 39 in the Q3 MD&A.

In addition, a prospective purchaser of Debentures should carefully consider the risk factors described in this section which relate to the Acquisition, the Instalment Receipts, the Debentures and the post-Acquisition business and operations of the Corporation and Empire, as well as the other information contained in this Prospectus (including the documents incorporated herein by reference).

Risk Factors Relating to the Acquisition

Algonquin may fail to complete the Acquisition

The closing of the Acquisition is subject to the normal commercial risks that the Acquisition will not close on the terms negotiated (including with respect to the consideration to be paid for the common stock of Empire) or at all. The completion of the Acquisition is subject to receipt of Empire Shareholder Approval and satisfaction of the other Approval Conditions, including expiration or termination of any applicable period under the HSR Act, CFIUS Approval, obtaining the approval of each of FERC, the FCC and the State Commissions and the satisfaction or waiver of certain closing conditions contained in the Acquisition Agreement, including the absence of any law or judgement that prevents, makes illegal or prohibits the consummation of the Acquisition. The failure to obtain the required approvals or satisfy or waive the conditions contained in the Acquisition Agreement may result in the termination of the Acquisition Agreement. There is no assurance that such closing conditions will be satisfied or waived. Accordingly, there can be no assurance that Algonquin will complete the Acquisition in the timeframe or on the basis described herein, if at all. The termination of the Acquisition Agreement may have a negative effect on the price of the Instalment Receipts, the Debentures and the Common Shares and will result in the redemption of the Debentures. If the closing of the Acquisition does not take place as contemplated, the Corporation could suffer adverse consequences, including the loss of investor confidence. See "The Acquisition Agreement – Closing Conditions".

The cash purchase price could increase

Empire is a public company and its directors owe fiduciary duties to Empire shareholders (and other stakeholders), which may require them to consider competing offers to purchase the common stock of Empire as alternatives to the Acquisition. The Acquisition Agreement preserves the ability of the directors of Empire to accept an alternative or competing offer in certain circumstances if such offer constitutes a Superior Proposal (as defined in the Acquisition Agreement). If a Superior Proposal to acquire Empire is made, and if the Superior Proposal results in Empire's board of directors making an Adverse Recommendation Change, if requested by Algonquin, Empire and its Representatives are required to negotiate in good faith with Algonquin regarding any revisions to the Acquisition Agreement committed to in writing by Algonquin, which could result in an increase to the cash purchase price of the Acquisition or to other terms and conditions of the Acquisition. See "The Acquisition Agreement".

Length of time required to complete the Acquisition is unknown

As described above under "– Algonquin may fail to complete the Acquisition", the closing of the Acquisition is subject to the receipt of required Empire Shareholder Approval and regulatory approvals and the satisfaction of other closing conditions contained in the Acquisition Agreement. There is no certainty, nor can Algonquin provide any assurance, as to when these conditions will be satisfied, if at all. A substantial delay in obtaining regulatory approvals or the imposition of unfavourable terms and/or conditions in such approvals could have a material adverse effect on the Corporation's ability to complete the Acquisition and on the Corporation's or Empire's business, financial condition or results of operations. In addition, in the event that such regulatory agencies imposed unfavorable terms and/or conditions on Algonquin or any Empire utility (including the requirement to sell or divest of certain assets or limitations on the future conduct of the combined entities), the Corporation could still be required to complete the transaction on the terms set forth in the Acquisition Agreement. Algonquin intends to complete the Acquisition as soon as practicable after obtaining the required Empire Shareholder Approval and regulatory approvals and satisfying the other required closing conditions. See "The Acquisition Agreement – Closing Conditions".

Foreign exchange risk

The cash consideration for the Acquisition is required to be paid in U.S. dollars, while funds raised in the Offering, which will constitute a significant portion of the funds ultimately used to finance the Acquisition, are denominated in Canadian dollars. See "Use of Proceeds". As a result, increases in the value of the U.S. dollar versus the Canadian dollar prior to payment of the final instalment will increase the purchase price translated in Canadian dollars and thereby reduce the proportion of the purchase price for the Acquisition ultimately obtained by Algonquin under the Offering, which could cause a failure to realize the anticipated benefits of the Acquisition.

In addition, the operations of Empire are conducted in U.S. dollars. Following the Acquisition, the consolidated net income and cash flows of Algonquin will be impacted to a much greater extent by movements in the U.S. dollar relative to the Canadian dollar. In particular, decreases in the value of the U.S. dollar versus the Canadian dollar following the Acquisition, could negatively impact the Corporation's net income as reported in Canadian dollars, which could cause a failure to realize the anticipated benefits of the Acquisition.

Algonquin may or may not enter into hedging arrangements to mitigate these exposures. The failure to enter into hedging arrangements could result in adverse impacts greater than if hedging had been used. Entering into hedging arrangements could result in limiting positive impacts if hedging had not been used.

Significant demands will be placed on Algonquin as a result of the Acquisition

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

Failure to pay the final instalment will negatively impact Algonquin's consolidated capitalization

Completion of the Acquisition is not conditional on the completion of the Offering by the Corporation or on the Corporation obtaining financing on favourable terms or at all. If a material amount due on payment of the final instalment is not paid by holders of Instalment Receipts and the Corporation is not able to quickly realize on the Debentures pledged to secure the obligation to pay the final instalment, the Corporation will not be able to use those proceeds to repay the Acquisition Credit Facilities. As a result, it may take Algonquin longer than anticipated to repay the Acquisition Credit Facilities which may have a negative impact on the consolidated capitalization of Algonquin until such time as the Acquisition Credit Facilities have been repaid by Algonquin in full.

Acquisition Credit Facilities may become unavailable

The commitment of the lenders to enter into the Acquisition Credit Facilities is subject to certain standard conditions which may result in such facilities becoming unavailable to Algonquin in certain circumstances. If the Acquisition Credit Facilities become unavailable to Algonquin, Algonquin may not be able to complete the Acquisition. The inability of Algonquin to complete the Acquisition will result in redemption of the Debentures. See "Financing the Acquisition – Acquisition Credit Facilities".

Alternate sources of funding that would be used to fund the Acquisition or replace the Acquisition Credit Facilities may not be available

The cash purchase price of the Acquisition and the Acquisition-Related Expenses will be financed at the closing of the Acquisition with a combination of some or all of the following: (i) net proceeds of the first instalment under the Offering; (ii) net proceeds of any subsequent bond or other debt offerings; (iii) amounts drawn under the Acquisition Credit Facilities; and (iv) existing cash on hand and other sources available to the Corporation.

There is no guarantee that alternate sources of funding will be available to Algonquin or its affiliates at the desired time or at all, or on cost-efficient terms. The inability to obtain alternate sources of funding to fund the Acquisition or replace the Acquisition Credit Facilities may negatively impact the financial performance of Algonquin, including the extent to which the Acquisition is accretive. In addition, any movement in interest rates that could affect the underlying cost of these instruments may affect the expected accretion of the Acquisition. Algonquin may enter into hedging arrangements to mitigate this risk.

Algonquin does not currently control Empire and its subsidiaries

Although the Acquisition Agreement contains covenants on the part of Empire regarding the operation of its business prior to closing the Acquisition, Algonquin will not control Empire and its subsidiaries until completion of the Acquisition and Empire's business and results of operations may be adversely affected by events that are outside of the Corporation's control during the intervening period. Historic and current performance of Empire's business and operations may not be indicative of success in future periods. The future performance of Empire may be influenced by, among other factors, weather, economic downturns, increased environmental regulation, turmoil in financial markets, unfavourable regulatory decisions, rising interest rates and other factors beyond the Corporation's control. As a result of any one or more of these factors, among others, the operations and financial performance of Empire may be negatively affected which may adversely affect the future financial results of Algonquin. See "– Risk Factors Relating to the Post-Acquisition Business and Operations of the Corporation and Empire".

Algonquin expects to incur significant Acquisition-Related Expenses

Algonquin expects to incur a number of costs associated with completing the Acquisition. The substantial majority of these costs will be non-recurring expenses resulting from the Acquisition and will consist of transaction costs related to the Acquisition, including costs relating to the financing of the Acquisition and obtaining regulatory approval. Additional unanticipated costs may be incurred.

Information relating to Empire in this Prospectus has been obtained from Empire or its public disclosure record

All information relating to Empire or its affiliates contained in this Prospectus has been obtained from Empire or taken from Empire's public disclosure record. Although the Corporation has conducted what it believes to be a prudent and thorough level of investigation in connection with the Acquisition and the disclosure relating to Empire contained in this Prospectus, an unavoidable level of risk remains regarding the accuracy and completeness of such information. While Algonquin has no reason to believe the information obtained from Empire or taken from the public disclosure record is misleading, untrue or incomplete, Algonquin cannot assure the accuracy or completeness of such information nor can Algonquin compel Empire to disclose events which may have occurred or may affect the completeness or accuracy of such information but which are unknown to Algonquin.

Risk Factors Relating to the Post-Acquisition Business and Operations of Algonquin and Empire

Algonquin will substantially increase its amount of indebtedness following the Acquisition

After giving effect to the Acquisition, Algonquin will have a significant amount of debt, including US$.9 billion of debt of Empire assumed by Algonquin as a result of the Acquisition. As of September 30, 2015, on a pro forma basis after giving effect to the Acquisition, but assuming conversion of all Debentures to Common Shares, details of which are included in the capitalization table provided herein, Algonquin would have approximately $4.1 billion of total indebtedness outstanding. See "Capitalization". Algonquin will substantially increase its amount of indebtedness following the Acquisition and such increased indebtedness may adversely affect Algonquin's cash flow and ability to operate its business.

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

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

The Acquisition could also result in a downgrade of the credit ratings of Empire and The Empire District Gas Company as well as significant mandatory redemptions of five outstanding series of bonds if the credit rating of either company, or of Algonquin as the acquiror, falls below "BB+" or lower by S&P or "Ba1" or lower by Moody's.

Should such an event occur, Empire must give written notice to the bond trustee and bondholders within five days of Empire becoming aware of a downgrade. The notice must include an offer to purchase all of the outstanding bonds. The purchase date must be at least 30 days after the notice, but not more than 60 days after the notice. The bondholder can accept or reject the offer and must deliver notice of its acceptance at least five days prior to the proposed purchase date. The bonds must be purchased at 100% of the principal amount, together with accrued and unpaid interest.

Algonquin's historical and pro forma combined financial information may not be representative of the results of the Corporation following the Acquisition

The pro forma combined financial information included in this Prospectus has been prepared using the consolidated historical financial statements of Algonquin and the consolidated historical financial statements of Empire and does not purport to be indicative of the financial information that will result from the operations of Algonquin on a consolidated basis following the Acquisition. In addition, the pro forma combined financial information included in this Prospectus is based in part on certain assumptions regarding the Acquisition that Algonquin currently believes are reasonable. Algonquin makes no assurances that its current assumptions will prove to be accurate over time. Accordingly, the historical and pro forma financial information included in this Prospectus does not necessarily represent the Corporation's results of operations and financial condition had Algonquin and Empire operated as a combined entity during the periods presented, or of the Corporation's results of operations and financial condition in the future. The Corporation's potential for future business success and operating profitability must be considered in light of the risks, uncertainties, expenses and difficulties typically encountered by recently combined companies.

In preparing the pro forma financial information contained in this Prospectus, Algonquin has given effect to, among other items, the Offering, the Acquisition Credit Facilities, the completion of the Acquisition and the assumption of Empire's outstanding indebtedness. Algonquin has also assumed that the Debentures will be converted into Common Shares on or immediately following the Final Instalment Date. While management believes that the estimates and assumptions underlying the pro forma financial information are reasonable, such assumptions and estimates may be materially different than the Corporation's actual experience following completion of the Acquisition. See also "– Risk Factors Relating to the Acquisition" and "Presentation of Financial Information". See the notes to the pro forma financial statements of Algonquin in this Prospectus.

Potential undisclosed liabilities associated with the Acquisition

In connection with the Acquisition, there may be liabilities of Empire and its subsidiaries that the Corporation failed to discover or was unable to quantify in the due diligence which it conducted prior to the execution of the Acquisition Agreement. The discovery or quantification of any material liabilities of Empire and its subsidiaries could have a material adverse effect on the Corporation's business, financial condition, results of operations or future prospects.

Algonquin may be unable to successfully combine the businesses of Algonquin and Empire and realize the anticipated benefits of the Acquisition

Algonquin believes that the Acquisition will provide benefits to the Corporation. See "The Acquisition – Acquisition Highlights". However, there is a risk that some or all of the expected benefits of the Acquisition may fail to materialize, or may not occur within the time periods anticipated by the Corporation. The realization of such benefits may be affected by a number of factors, many of which are beyond the control of the Corporation. The challenge of combining previously independent businesses makes evaluating the Corporation's business and future financial prospects difficult. The past financial performance of the Corporation may not be indicative of its future financial performance. In addition, any regulatory approvals required in connection with the Acquisition may include terms which could have an adverse effect on the Corporation's financial performance, including reduced revenues or investment recovery, increased competition or costs, or adverse alterations to the rate structure.

Failure to realize the anticipated benefits of the Acquisition may impact the financial performance of the Corporation, the price of its Common Shares and the ability of Algonquin to continue to pay dividends on its Common Shares at current rates or at all. The declaration of dividends by the Corporation is at the discretion of the Board of Directors and the Board of Directors may determine at any time to cease paying dividends. See "Dividend Policy" and "– Risk Factors Relating to the Post-Acquisition Business and Operations of the Corporation and Empire".

The combination of the businesses of Algonquin and Empire will require the dedication of substantial effort, time and resources on the part of Algonquin's management which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. There can be no assurance that management will be able to combine the operations of each of the businesses successfully or achieve any of the benefits that are anticipated as a result of the Acquisition. The extent to which the anticipated benefits are realized and the timing of such cannot be assured. Any inability of management to successfully combine the operations of Algonquin and Empire could have a material adverse effect on the Corporation's business, financial condition, results of operations or future prospects.

Algonquin may not be successful in retaining the services of key personnel of Empire following the Acquisition

Algonquin currently intends to retain key personnel of Empire following the completion of the Acquisition to continue to manage and operate Empire as a separate operating company. Algonquin will compete with other potential employers for employees, and it may not be successful in keeping the services of the executives and other employees of Empire that it needs to realize the anticipated benefits of the Acquisition. The Corporation's failure to retain key personnel to remain as part of the management team of Empire in the period following the Acquisition could have a material adverse effect on the business and operations of Empire and Algonquin on a consolidated basis.

Algonquin is subject to risks associated with its results of operations and financing risks

Management of Algonquin believes, based on its current expectations as to the Corporation's future performance (which reflects, among other things, the completion of the Acquisition), that the cash flow from its operations and funds available to it under its Revolving Facilities and its ability to access capital markets will be adequate to enable the Corporation to finance its operations, execute its business strategy and maintain an adequate level of liquidity. However, expected revenue and the costs of planned capital expenditures are only estimates. Moreover, actual cash flows from operations are dependent on regulatory, market and other conditions that are beyond the control of the Corporation. As such, no assurance can be given that management's expectations as to future performance will be realized. In addition, management's expectations as to the Corporation's future performance reflect the current state of its information about Empire and its operations and there can be no assurance that such information is correct and complete in all material respects.

The Corporation's degree of leverage could have adverse consequences for Algonquin, particularly if a significant portion of the Acquisition Credit Facilities are drawn to complete the Acquisition or if a significant portion of the Debentures are not converted into Common Shares by the holders thereof. The significant increase in the degree of the Corporation's leverage could, among other things, limit the Corporation's ability to obtain additional financing for working capital, investment in subsidiaries, capital expenditures, debt service requirements, acquisitions and general corporate or other purposes; restrict the Corporation's flexibility and discretion to operate its business; limit the Corporation's ability to declare dividends on its Common Shares; require Algonquin to dedicate a portion of cash flows from operations to the payment of interest on its existing indebtedness, in which case such cash flows will not be available for other purposes; cause ratings agencies to re-evaluate or downgrade the Corporation's existing credit ratings; expose Algonquin to increased interest expense on borrowings at variable rates; limit the Corporation's ability to adjust to changing market conditions; place Algonquin at a competitive disadvantage compared to its competitors that have less debt; make Algonquin vulnerable to any downturn in general economic conditions; and render Algonquin unable to make expenditures that are important to its future growth strategies.

The Corporation will need to refinance or reimburse amounts outstanding under the Corporation's existing consolidated indebtedness over time. There can be no assurance that any indebtedness of the Corporation will be refinanced or that additional financing on commercially reasonable terms will be obtained, if at all. In the event that such indebtedness cannot be refinanced, or if it can be refinanced on terms that are less favourable than the current terms, the ability of the Corporation to declare dividends may be adversely affected.

The ability of the Corporation to meet its debt service requirements will depend on its ability to generate cash in the future, which depends on many factors, including the financial performance of the Corporation, debt service obligations, the realization of the anticipated benefits of the Acquisition and working capital and future capital expenditure requirements. In addition, the ability of the Corporation to borrow funds in the future to make payments on outstanding debt will depend on the satisfaction of covenants in existing credit agreements and other agreements. A failure to comply with any covenants or obligations under the Corporation's consolidated indebtedness could result in a default under one or more such instruments, which, if not cured or waived, could result in the termination of distributions by the Corporation and permit acceleration of the relevant indebtedness. If such indebtedness were to be accelerated, there can be no assurance that the assets of the Corporation would be sufficient to repay such indebtedness in full. There can also be no assurance that the Corporation will generate cash flow in amounts sufficient to pay outstanding indebtedness or to fund any other liquidity needs.

National and local economic conditions can have a significant impact on the results of operations, net income and cash flows at Empire and its subsidiaries

The business of Empire is concentrated in Missouri with business also conducted in Arkansas, Oklahoma and Kansas. Economic conditions in these states and in Empire's service territories could change and if they should worsen, retail customer growth rates may stagnate or decline and customers' energy usage may further decline, adversely affecting Empire's results of operations, net income and cash flows and those of the Corporation following the Acquisition.

Developments in technology could reduce demand for electricity and gas

Research and development activities are ongoing for new technologies that produce power or reduce power consumption. These technologies include renewable energy, customer-oriented generation, energy storage, energy efficiency and more energy efficient appliances and equipment. Advances in these, or other technologies, could reduce the cost of producing electricity, transporting gas or make the existing generating facilities of Empire uneconomic. In addition, advances in such technologies could reduce electrical or natural gas demand, which could negatively impact the results of operations, net income and cash flows of Empire and those of the Corporation following the Acquisition.

Empire is exposed to increases in costs and reductions in revenue which Empire cannot control and which may adversely affect its business, financial condition and results of operations

The primary drivers of Empire's regulated electric operating margins in any period are: (i) rates Empire can charge its customers, including timing of new rates; (ii) weather; (iii) customer growth and usage; and (iv) general economic conditions. Of the factors driving margins, weather has the greatest short-term effect on the demand for electricity for Empire's regulated business. Mild weather reduces demand and, as a result, Empire's regulated electric operating revenues. In addition, changes in customer demand due to downturns in the economy, energy efficiency or increased use of self-generation and distributed energy technologies could reduce Empire's revenues.

The primary drivers of Empire's regulated electric operating expenses in any period are: (i) fuel and purchased power expenses; (ii) operating, maintenance and repairs expense, including repairs following severe weather and plant outages; (iii) taxes; and (iv) non-cash items such as depreciation and amortization expense. Although Empire generally recovers these expenses through its rates, there can be no assurance that Empire will recover all or any part of such increased costs in future rate cases.

The primary drivers of Empire's regulated gas operating revenues in any period are: (i) rates Empire can charge its customers; (ii) weather; (iii) customer growth; (iv) the cost of natural gas and interstate pipeline transportation charges; and (v) general economic conditions. Because natural gas is heavily used for residential and commercial heating, the demand for this product depends heavily upon weather patterns throughout Empire's natural gas service territory and a significant amount of Empire's regulated natural gas revenues are recognized in the first and fourth quarters related to the heating seasons. Accordingly, Empire's natural gas operations have historically generated less revenues and income when weather conditions are warmer in the winter.

The primary driver of Empire's regulated gas operating expense in any period is the price of natural gas.

Significant increases in regulated electric and gas operating expenses or reductions in electric and gas operating revenues may occur and result in a material adverse effect on Empire's business, financial condition and results of operations.

Energy conservation, energy efficiency, distributed generation and other factors that reduce energy demand could adversely affect Empire's business, financial condition and results of operations

Regulatory and legislative bodies have proposed or introduced requirements and incentives to reduce energy consumption. Conservation and energy efficiency programs are designed to reduce energy demand. Unless there is a regulatory solution ensuring recovery, declining usage will result in an under-recovery of Empire's fixed costs. Macroeconomic factors resulting in low economic growth or contraction within Empire's service territories could also reduce energy demand. Any such reductions in energy demand could adversely affect Empire's business, financial condition and results of operations.

In addition, significant technological advancements are taking place in the electric industry, including advancements related to self-generation and distributed energy technologies such as fuel cells, micro turbines, wind turbines and solar cells. Adoption of these technologies may increase because of advancements or government subsidies reducing the cost of generating electricity through these technologies to a level that is competitive with Empire's current methods of generating electricity. There is also a perception that generating electricity through these technologies is more environmentally friendly than generating electricity with fossil fuels. Increased adoption of these technologies would reduce demand for Empire's electricity but would not necessarily reduce Empire's investment and operating requirements due to Empire's obligation to serve customers, including those self-generation customers whose equipment has failed for any reason to provide the power they need. In addition, self-generating customers do not currently pay a share of the costs necessary to operate Empire's transmission and distribution system. As a result, the pool of customers from whom fixed costs are recovered would be reduced, potentially resulting in under-recovery of Empire's fixed costs and upward price pressure on Empire's remaining customers. If Empire were unable to adjust Empire's prices to reflect such reduced electricity demand and any related use of net energy metering (which allows self-generating customers to receive bill credits for surplus power), Empire's business, financial condition and results of operations could be adversely affected. In addition, since a portion of Empire's costs are recovered through charges based upon the volume of power delivered, reductions in electricity deliveries will affect the timing of Empire's recovery of those costs and may require changes to Empire's rate structures.

Empire is subject to environmental laws and the incurrence of environmental liabilities which may adversely affect Empire's business, financial condition and results of operations

Empire is subject to extensive federal, state and local regulation with regard to air and other environmental matters. Failure to comply with these laws and regulations could have a material adverse effect on Empire's results of operations and financial position. In addition, new environmental laws and regulations, and new interpretations of existing environmental laws and regulations, have been adopted and may in the future be adopted which may substantially increase Empire's future environmental expenditures for both new and existing facilities. Compliance with current and potential future air emission standards (such as those limiting emission levels of sulfur dioxide (SO_2), emissions of mercury, other hazardous pollutants (HAPS), nitrogen oxide (NOx), and carbon dioxide (CO_2)) has required, and may in the future require, significant environmental expenditures. Although Empire has historically recovered such costs through Empire's regulated rates, there can be no assurance that Empire will recover all or any part of such increased costs in future rate cases. The incurrence of additional material environmental costs which are not recovered in Empire's rates may result in a material adverse effect on Empire's business, financial condition and results of operations.

Empire is exposed to factors that can increase its fuel and purchased power expenditures, including disruption in deliveries of coal or natural gas, decreased output from its power plants, failure of performance by purchased power counterparties and market risk in its fuel procurement strategy related to its regulated electrical generating stations

Fuel and purchased power costs are Empire's largest expenditures. Increases in the price of coal, natural gas or the cost of purchased power will result in increased electric operating expenditures. Given that Empire has a fuel cost recovery mechanism in all of its jurisdictions, Empire's net income exposure to the impact of the risks discussed above is significantly reduced. However, cash flow could still be impacted by these increased expenditures. Empire is also subject to prudency reviews which could negatively impact Empire's net income if a regulatory commission would conclude that Empire's costs were incurred imprudently.

Empire depends upon regular deliveries of coal as fuel for its Asbury, Iatan and Plum Point plants. Substantially all of this coal comes from mines in the Powder River Basin of Wyoming and is delivered to the plants by train. Production problems in these mines, railroad transportation or congestion problems, or unavailability of trains could affect delivery cycle times required to maintain plant inventory levels, causing Empire to implement coal conservation and supply replacement measures to retain adequate reserve inventories at its facilities. These measures could include some or all of the following: reducing the output of Empire's coal plants, increasing the utilization of Empire's gas-fired generation facilities, purchasing power from other suppliers, adding additional leased trains to Empire's supply system and purchasing locally mined coal which can be delivered without using railroads. Such measures could result in increased fuel and purchased power expenditures.

Natural gas is delivered to Empire's generation fleet at Riverton, State Line, and Energy Center via Southern Star Central Gas Pipeline. Although Empire has firm transportation contracts in place for a limited volume of daily natural gas deliveries, the actual delivery of natural gas can still be uncertain during winter peaking weather. The inability to procure commodity or pipeline curtailments for non-firm delivery causes Empire to either rely on fuel oil as a back-up fuel for generation at State Line Unit No. 1 or Energy Center units, and/or limit the generation offered into the SPP IM from State Line Combined Cycle and Riverton. As a result, Empire could incur higher fuel and purchased power costs than if the units were available for full commitment and dispatch.

Empire has also established a risk management practice of purchasing contracts for future fuel needs to meet underlying customer needs and manage cost and pricing uncertainty. Within this activity, Empire may incur losses from these contracts. By using physical and financial instruments, Empire is exposed to credit risk and market risk. Market risk is the exposure to a change in the value of commodities caused by fluctuations in market variables, such as price. The fair value of derivative financial instruments that Empire holds is adjusted cumulatively on a monthly basis until prescribed determination periods. At the end of each determination period, which is the last day of each calendar month in the period, any realized gain or loss for that period related to the contract will be reclassified to fuel expense and recovered or refunded to the customer through Empire's fuel adjustment mechanisms. Credit risk is the risk that the counterparty might fail to fulfill its obligations under contractual terms.

Empire is subject to regulation in the jurisdictions in which it operates regulated utilities, including the rates that it can charge customers

Empire is subject to comprehensive regulation by federal and state utility regulatory agencies, which significantly influences its operating environment and ability to recover costs from utility customers. The utility commissions in the states where Empire operates regulate many aspects of its utility operations, including the rates that Empire can charge customers, siting and construction of facilities, pipeline safety and compliance, customer service and Empire's ability to recover the costs that it incurs, including capital expenditures and fuel and purchased power costs.

The FERC has jurisdiction over wholesale rates for electric transmission service and electric energy sold in interstate commerce. Federal, state and local agencies also have jurisdiction over many of Empire's other activities.

Empire is also subject to prudency and similar reviews by regulators of costs that it incurs, including capital expenditures, fuel and purchased power costs and other operating costs.

Empire is unable to predict the impact of the regulatory activities of any of these agencies, including any regulatory disallowances that could result from prudency reviews, on its operating results. Despite Empire's requests, these regulatory commissions have sole discretion to leave rates unchanged, grant increases or order decreases in the base rates Empire charges its utility customers. They have similar authority with respect to Empire's recovery of increases in its fuel and purchased power costs. Rate proceedings through which Empire's prices and terms of service are determined typically involve numerous parties including customers, consumer advocates and governmental entities, some of whom take positions adverse to Empire. In addition, regulators' decisions may be appealed to the courts by Empire or other parties to the proceedings. These factors may lead to uncertainty and delays in implementing changes to Empire's prices or terms of service. If Empire's costs increase and Empire is unable to recover increased costs through base rates or fuel adjustment clauses, or if Empire is unable to fully recover its investments in new facilities, Empire's results of operations could be materially adversely affected. Changes in regulations or the imposition of additional regulations could also have a material adverse effect on Empire's results of operations.

In addition, although the current rate making process provides recovery of some future changes in rate base and operating costs, it does not reflect all changes in costs for the period in which new retail rates will be in place. This results in a lag (commonly referred to as "regulatory lag") between the time Empire incurs costs and the time when it can start recovering the costs through rates. This may result in under-recovery of costs, failure to earn the authorized return on investment, or both.

Operations risks may adversely affect Empire's business and financial results

The operation of Empire's regulated electric generation, and electric and gas transmission and distribution systems involves many risks, including breakdown or failure of expensive and sophisticated equipment, processes and personnel performance; inability to attract and retain management and other key personnel; workplace and public safety; operating limitations that may be imposed by workforce issues, equipment conditions, environmental or other regulatory requirements; fuel supply or fuel transportation reductions or interruptions; transmission scheduling constraints; unauthorized physical access to Empire's facilities; and catastrophic events such as fires, explosions, severe weather (including tornadoes and ice storms), acts of terrorism or other similar occurrences.

Empire has implemented training and preventive maintenance programs and has security systems and related protective infrastructure in place, but there is no assurance that these programs will prevent or minimize future breakdowns, outages or failures of Empire's generation facilities or related business processes. In those cases, Empire would need to either produce replacement power from its other facilities or purchase power from other suppliers at potentially volatile and higher cost in order to meet Empire's sales obligations, or implement emergency back-up business system processing procedures. In addition, certain catastrophic events can inflict extensive damage to Empire's equipment and facilities which can require Empire to incur additional operating and maintenance expense and additional capital expenditures. Empire's prices may not always be adjusted timely and adequately to reflect these higher costs.

These and other operating events and conditions may reduce Empire's revenues, increase costs, or both, and may materially affect its results of operations, financial position and cash flows.

The regional power market in which Empire operates has changing market and transmission structures, which could have an adverse effect on Empire's results of operations, financial position and cash flows

The SPP RTO is mandated by the FERC to ensure a reliable power supply, an adequate transmission infrastructure and competitive wholesale electricity prices. The SPP RTO functions as reliability coordinator, tariff administrator and regional scheduler for its member utilities, including Empire. Essentially, the SPP RTO independently operates Empire's transmission system as it interfaces and coordinates with the regional power grid. SPP RTO activities directly impact Empire's control of owned generating assets and the development and cost of transmission infrastructure projects within the SPP RTO region. The cost allocation methodology applied to these transmission infrastructure projects will increase Empire's operating expenses.

The SPP RTO implemented a Day-Ahead Market, or IM, in March 2014. The SPP IM functions as a centralized dispatch, where Empire and other members submit offers to sell power and bids to purchase power. The SPP matches offers and bids to supply the next day generation needs of its members. It is expected that 90%-95% of all next day generation needed throughout the SPP territory will be cleared through this IM. This change could impact Empire's fuel costs, however, the net financial effect of these IM transactions will be processed through Empire's fuel adjustment mechanisms.

Information concerning recent and pending SPP RTO and other FERC activities can be found in Note 3 in the notes to Empire's audited consolidated financial statements included in this Prospectus.

Security breaches, criminal activity, terrorist attacks and other disruptions to Empire's information technology infrastructure could directly or indirectly interfere with Empire's operations, could expose Empire or Empire's customers or employees to a risk of loss, and could expose Empire to liability, regulatory penalties, reputational damage and other harm to Empire's business

Empire relies upon information technology networks and systems to process, transmit and store electronic information, and to manage or support a variety of business processes and activities, including the generation, transmission and distribution of electricity, supply chain functions, and the invoicing and collection of payments from Empire's customers. Empire also use information technology systems to record, process and summarize financial information and results of operations for internal reporting purposes and to comply with financial reporting, legal and tax requirements. Empire's technology networks and systems collect and store sensitive data including system operating information, proprietary business information belonging to Empire and third parties, and personal information belonging to Empire's customers and employees.

Empire's information technology networks and infrastructure may be vulnerable to damage, disruptions or shutdowns due to attacks by hackers or breaches due to employee error or malfeasance, or other disruptions during software or hardware upgrades, telecommunication failures or natural disasters or other catastrophic events. The occurrence of any of these events could impact the reliability of Empire's generation, transmission and distribution systems; could expose Empire, Empire's customers or Empire's employees to a risk of loss or misuse of information; and could result in legal claims or proceedings, liability or regulatory penalties against Empire, damage Empire's reputation or otherwise harm Empire's business. Empire cannot accurately assess the probability that a security breach may occur, despite the measures that Empire takes to prevent such a breach, and Empire is unable to quantify the potential impact of such an event. Empire can provide no assurance that Empire will identify and remedy all security or system vulnerabilities or that unauthorized access or error will be identified and remedied.

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

Empire may be unable to recover increases in the cost of natural gas from Empire's natural gas utility customers, or may lose customers as a result of any price increase

In Empire's regulated natural gas utility business, Empire is permitted to recover the cost of gas directly from Empire's customers through the use of a PGA provision. Empire's PGA provision is regularly reviewed by the MPSC. In addition to reviewing Empire's adjustments to customer rates, the MPSC reviews Empire's costs for prudency as well. To the extent the MPSC may determine certain costs were not incurred prudently, it could adversely affect Empire's gas segment earnings and cash flows. In addition, increases in natural gas costs affect total prices charged to Empire's customers and, therefore, the competitive position of gas relative to electricity and other forms of energy. Increases in natural gas costs may also result in lower usage by customers unable to switch to alternate fuels. Such disallowed costs or customer losses could have a material adverse effect on Empire's business, financial condition and results of operations.

Any reduction in Empire's credit ratings could materially and adversely affect Empire's business, financial condition and results of operations

The ratings indicate the agencies' assessment of Empire's ability to pay the interest and principal of these securities. A rating is not a recommendation to purchase, sell or hold securities and each rating should be evaluated independently of any other rating. The lower the rating, the higher the interest cost of the securities when they are sold. In addition, a downgrade in Empire's senior unsecured long-term debt rating would result in an increase in Empire's borrowing costs under its bank credit facility. If any of Empire's ratings fall below investment grade (investment grade is defined as Baa3 or above for Moody's and BBB- or above for S&P), Empire's ability to issue short-term debt, commercial paper or other securities or to market those securities would be impaired or made more difficult or expensive. Therefore, any such downgrades could have a material adverse effect on Empire's business, financial condition and results of operations. In addition, any actual downgrade of Empire's commercial paper rating from Moody's or Fitch may make it difficult for Empire to issue commercial paper. To the extent Empire is unable to issue commercial paper, Empire will need to meet its short-term debt needs through borrowings under its revolving credit facilities, which may result in higher costs.

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

The cost and schedule of Empire's construction projects may materially change

Empire's capital expenditure budget for 2016 through 2018 is estimated to be US$409.0 million. This includes expenditures for environmental upgrades to Empire's existing facilities and additions to Empire's transmission and distribution systems, including costs to retire assets. There are risks that actual costs may exceed budget estimates, delays may occur in obtaining permits and materials, suppliers and contractors may not perform as required under their contracts, there may be inadequate availability, productivity or increased cost of qualified craft labour, start-up activities may take longer than planned, the scope and timing of projects may change, and other events beyond Empire's control may occur that may materially affect the schedule, budget, cost and performance of projects. To the extent the completion of projects is delayed, Empire expects that the timing of receipt of increases in base rates reflecting Empire's investment in such projects will be correspondingly delayed. Costs associated with these projects will also be subject to prudency review by regulators as part of future rate case filings and recovery of all costs may not be allowed.

Financial market disruptions may increase financing costs, limit access to the credit markets or cause reductions in investment values in Empire's pension plan assets

Although Empire believes it is unlikely it will have difficulty accessing the markets for the capital needed for future capital expenditures (if such a need arises), financing costs could fluctuate. Financial market disruptions and volatility in discount rates could lead to increased funding obligations due to reduced asset values and increased benefit obligations. During 2014, Empire's net pension and OPEB liability increased US$40.5 million. Empire's funding policy is to contribute annually an amount at least equal to the actuarial cost of postretirement benefits. The actual minimum pension funding requirements are determined based on the results of the actuarial valuations and the performance of Empire's pension assets during the current year. Future market changes could result in increased pension and OPEB liabilities and funding obligations.

Failure to attract and retain an appropriately qualified workforce could adversely affect Empire's business, financial condition and results of operations

Certain events, such as an aging workforce, mismatch of skill set or complement to future needs, or unavailability of contract resources may lead to operating challenges and increased costs. The challenges include lack of resources, loss of knowledge base and the lengthy time required for skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, may rise. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to new employees, or future availability and cost of contract labour may adversely affect the ability to manage and operate the business. If Empire is unable to successfully attract and retain an appropriately qualified workforce, Empire's business, financial condition and results of operations could be adversely affected.

Empire is subject to adverse publicity and reputational risks, which makes Empire vulnerable to negative customer perception and increased regulatory oversight or other sanctions

Like other utility companies, Empire has a large consumer customer base and, as a result, is subject to public criticism focused on the reliability of Empire's distribution services and the speed with which Empire is able to respond to outages caused by storm damage or other unanticipated events. Adverse publicity of this nature may render legislatures, public utility commissions and other regulatory authorities and government officials, less likely to view public utility companies in a favorable light, and may cause Empire to be susceptible to less favorable legislative and regulatory outcomes or increased regulatory oversight. Unfavorable regulatory outcomes can include more stringent laws and regulations governing Empire's operations, such as reliability and customer service quality standards or vegetation management requirements, as well as fines, penalties or other sanctions or requirements. The imposition of any of the foregoing could have a material adverse effect on Empire's business, financial condition and results of operations.

Empire's businesses are sensitive to variations in weather and the effects of extreme weather, and have seasonal variations

Empire's businesses are affected by variations in general weather conditions and unusually severe weather. Energy sales by its electric and gas utilities are particularly sensitive to variations in weather conditions. Those utilities forecast energy sales on the basis of normal weather, which represents a long-term historical average. If climate change or other factors cause significant variations from normal weather, this could have a material impact on energy sales.

Risk Factors Relating to the Instalment Receipts

The balance of the Instalment Receipt purchase price remains outstanding and the failure of a holder of Instalment Receipts to pay the balance of the purchase price on or before the Final Instalment Date will have adverse consequences for the holder

Each Instalment Receipt purchased in the Offering represents an obligation of the holder of such security to pay $667 per $1,000 principal amount of Debentures on or before the Final Instalment Date. If the final instalment of the purchase price is not paid when due, the Defaulting Holder will no longer be able to pay the final instalment without the consent of the Selling Debentureholder. In addition, the Defaulting Holder will no longer be able to exercise the rights described under "Details of the Offering – Instalment Receipts – Rights and Privileges" and will cease to be entitled to any repayment of principal in respect of the Debenture represented by such Instalment Receipt. In addition, if the holder of an Instalment Receipt does not pay the final instalment when due, the Debentures evidenced by such Instalment Receipt may, at the Selling Debentureholder's option, upon compliance with applicable law and the terms of the Instalment Receipt Agreement, be forfeited to the Selling Debentureholder in full satisfaction of the Defaulting Holder's obligations or such Debentures may be sold and the Defaulting Holder will remain liable for any deficiency in the proceeds of such sale. The Selling Debentureholder will have the right to and may commence legal action against Defaulting Holders who do not pay the final instalment on or before the Final Instalment Date. The commencement of any such litigation by the Selling Debentureholder may negatively affect the Corporation and the Selling Debentureholder, and could have an adverse effect on the price of the Debentures and the Common Shares.

There is currently no market through which the Instalment Receipts may be sold

There is currently no market through which the Instalment Receipts may be sold and purchasers of Debentures may not be able to resell Instalment Receipts. There can be no assurance that an active trading market will develop for the Instalment Receipts after the Offering or, if developed, that such a market will be sustained. This may affect the pricing of the Instalment Receipts in the secondary market, the transparency and availability of trading prices, the liquidity of Instalment Receipts, and the extent of issuer regulation. If an active market for the Instalment Receipts fails to develop or be sustained, the prices at which the Instalment Receipts trade may be adversely affected. Whether or not the Instalment Receipts will trade at lower prices depends on many factors, including liquidity of the Instalment Receipts, prevailing interest rates and the market for similar securities, the market price of debt securities with maturities comparable to the Debentures, the market price of the Common Shares, general economic conditions and Algonquin's financial condition, historic financial performance and future prospects.

Algonquin has applied to list the Instalment Receipts (representing the Debentures) and the Common Shares issuable on the conversion of the Debentures on the TSX. Listing will be subject to the Corporation fulfilling all of the requirements of the TSX and there is no assurance that the TSX will approve such listing application. The Corporation has no current intention to list the Debentures for trading on the TSX or any other exchange as it currently anticipates all Debentures will be converted to Common Shares on the Final Instalment Date.

Fluctuations in trading price

An Instalment Receipt entitles the holder to unencumbered ownership of a Debenture upon payment of the final instalment on or before the Final Instalment Date. Interest rate movements will cause the value of debt instruments with a maturity comparable to the Debentures to fluctuate, and this will be reflected in the market price of the Instalment Receipts. The price volatility of the Instalment Receipts will be greater than the price volatility of debt instruments of a maturity comparable to the Debentures. This is due to the fact that the payment for the Instalment Receipts represents only 33.3% of the total principal amount payable for the underlying Debenture.

Further, the market price of the Common Shares underlying the Debentures may be volatile. This volatility may affect the ability of holders of Instalment Receipts to sell the Instalment Receipts at an advantageous price, particularly if the market price for Common Shares falls below the Conversion Price of Debentures represented by Instalment Receipts. In addition, it may result in greater volatility in the market price of the Instalment Receipts than would be expected for other debt securities or for non-convertible or non-exchangeable securities. Market price fluctuations in the Common Shares may be due to, among other things, the operating results of the Corporation failing to meet the expectations of securities analysts or investors in any quarter, downward revision in securities analysts' estimates, governmental regulatory action, market perception of the likelihood of the completion of the Acquisition, adverse changes in general market conditions or economic trends, acquisitions, dispositions or other material public announcements by Algonquin, or by Algonquin's competitors, along with a variety of additional factors. These broad market fluctuations may adversely affect the prices of the Instalment Receipts and the Common Shares.

Rights of holders of Instalment Receipts may change

Purchasers of Debentures will, prior to payment of the final instalment, be holders of Instalment Receipts and will be bound by the terms and conditions of the Instalment Receipt Agreement. The Instalment Receipt Agreement will provide that, pending payment of the final instalment, legal title to the Debentures offered hereby will be held by the Custodian on behalf of the Selling Debentureholder pursuant to the pledge to secure the payment of the final instalment. The terms and conditions of the Instalment Receipt Agreement may be amended in certain circumstances, including with the approval of holders of Instalment Receipts representing two-thirds of the principal amount of the Debentures represented thereby. The description of the Instalment Receipt Agreement contained in this Prospectus is qualified in its entirety by the provisions of such agreement, which should be reviewed by holders of Instalment Receipts. The Instalment Receipt Agreement will be filed by Algonquin on SEDAR on or about the Closing Date.

Right to receive unencumbered Debentures may terminate

The Corporation has the obligation to redeem the Debentures at a price equal to their principal amount plus accrued and unpaid interest following the earlier of: (i) notification to holders that the Approval Conditions will not be satisfied; (ii) termination of the Acquisition Agreement in accordance with its terms; and (iii) September 11, 2017 if the Final Instalment Notice has not been given on or before September 8, 2017. See "Details of the Offering – Debentures – Redemption". Accordingly, it is possible that Instalment Receipts will be outstanding for a very limited period of time. Upon such redemption, a holder will no longer be entitled to pay the final instalment or to receive any unencumbered Debentures and will only be entitled to receive a net payment equal to the redemption price less the amount of the final instalment otherwise payable by such holder to the Selling Debentureholder plus accrued and unpaid interest thereon. Until the Approval Conditions are satisfied and the Debentures are delivered to holders of Instalment Receipts pursuant to the Instalment Receipt Agreement, such holders have the rights described under "Details of the Offering – Instalment Receipts".

While the right of holders of Instalment Receipts to receive unencumbered Debentures may terminate as a result of a redemption by the Corporation of the Debentures as described herein, the Acquisition could potentially still be completed by the Corporation. If the Acquisition is completed following the redemption of the Debentures, holders of Instalment Receipts will not receive any of the benefits which may accrue to shareholders of the Corporation following completion of the Acquisition.

Acquisition may be completed on other terms

Both before and after payment of the final instalment, the Corporation may, in its sole discretion, amend the Acquisition Agreement and consummate the Acquisition on terms that may be substantially different from those contemplated in this Prospectus. Any such change will not affect the obligation of the holder of an Instalment Receipt to pay the final instalment on or before the Final Instalment Date. See "The Acquisition Agreement" and "– Risk Factors Relating to the Acquisition – Algonquin may fail to complete the Acquisition".

Risk Factors Relating to the Debentures

There is currently no market through which the Debentures may be sold

There is currently no market through which the Debentures may be sold and purchasers of Debentures may not be able to resell Debentures purchased under this Prospectus. The Corporation has not applied to list the Debentures for trading on the TSX, but has applied to list the Instalment Receipts (representing the Debentures) and the Common Shares issuable on the conversion of the Debentures. Accordingly, an investor who does not exercise the conversion privilege in respect of fully paid Debentures will be holding what Algonquin expects will be highly illiquid securities. There can be no assurance that an active trading market will develop for the Debentures after payment of the final instalment or, if developed, that such a market will be sustained. This may affect the pricing of the Debentures in the secondary market, the transparency and availability of trading prices, the liquidity of Debentures, and the extent of issuer regulation. If an active market for the Debentures fails to develop or be sustained, the prices at which the Debentures trade may be adversely affected. Whether or not the Debentures will trade at lower prices depends on many factors, including, among others, liquidity of the Debentures, prevailing interest rates and the market for similar securities, the market price of the Common Shares, general economic conditions and the Corporation's financial condition, historic financial performance and future prospects.

Fluctuations in trading price

After the Final Instalment Date, Debentures will stop accruing interest. Accordingly, their value will be a function of the value of the underlying Common Shares into which the Debenture is convertible. The market price of the Common Shares underlying the Debentures may be volatile. This volatility may affect the ability of holders of Debentures to sell the Debentures at an advantageous price. In addition, it may result in greater volatility in the market price of the Debentures than would be expected for other debt securities or non-convertible securities. Market price fluctuations in the Common Shares may be due to the operating results of the Corporation failing to meet the expectations of securities analysts or investors in any quarter, downward revision in securities analysts' estimates, governmental regulatory action, market perception of the likelihood of the completion of the Acquisition, adverse changes in general market conditions or economic trends, acquisitions, dispositions or other material public announcements by Algonquin, or by Algonquin's competitors, along with a variety of additional factors.

Existing and Prior Ranking of Indebtedness

On the Closing Date, the Corporation expects to have consolidated indebtedness of approximately \$3.0 billion (including the Debentures, excluding the Over-Allotment Option). After giving effect to the Acquisition, assuming receipt of the aggregate total amount of the final instalment for each of the Debentures and the use of such amounts to repay a portion of the Acquisition Credit Facilities, conversion of all Debentures into Common Shares and the assumption of Empire's outstanding indebtedness, management estimates that the consolidated indebtedness of the Corporation will be \$4.2 billion. See "Financing of the Acquisition" and "Capitalization".

The Debentures will be subordinate to all Senior Indebtedness of the Corporation. See "Details of the Offering – Debentures – Subordination". Therefore, in the event of the insolvency, bankruptcy, liquidation, reorganization, dissolution or winding up of the Corporation, the assets of the Corporation would be made available to satisfy its obligations with respect to the Debentures only after it has paid all of its secured creditors and all holders of Senior Indebtedness. Accordingly, all or a substantial portion of the Corporation's assets could be unavailable to satisfy the claims of holders of the Debentures. There may be insufficient assets remaining following such payments to pay amounts due on any or all of the Debentures then outstanding. See "– Risk Factors Relating to the Post-Acquisition Business and Operations of the Corporation and Empire".

The Debentures will be effectively subordinated to the debt and other liabilities of Algonquin's subsidiaries and to any future secured debt of Algonquin

Algonquin's subsidiaries will not guarantee or otherwise be responsible for the payment of principal or interest or other payments required to be made by Algonquin on the Debentures. Accordingly, the Debentures will be effectively subordinated to all existing and future liabilities (including trade payables and debt) of Algonquin's subsidiaries. In the event of an insolvency, bankruptcy, liquidation, reorganization or similar proceeding in respect of any of Algonquin's subsidiaries, holders of the Debentures will have no right to proceed against the assets of such subsidiaries. Creditors of such subsidiaries would generally be entitled to payment in full from such assets before any assets are made available for distribution to Algonquin to pay its debts and other obligations. The Debentures will also be effectively subordinated in right of payment to any future secured debt of Algonquin, to the extent of the value of the assets securing such debt.

Absence of covenant protection

The Indenture does not restrict the Corporation or any of its subsidiaries from incurring additional indebtedness for borrowed money or otherwise from mortgaging, pledging or charging their properties to secure any indebtedness or other financing. The Indenture does not contain any provisions specifically intended to protect holders of the Debentures in the event of a future leveraged transaction involving the Corporation or any of its subsidiaries.

The rights of holders of Debentures may change

Holders of Debentures will be bound by the terms and conditions of the Indenture. The terms and conditions of the Indenture may be amended in certain circumstances, including with the approval of two-thirds of holders of outstanding Debentures. The description of the Indenture contained in this Prospectus is qualified in its entirety by the provisions of the Indenture, which should be reviewed by holders of Instalment Receipts and Debentures. The Indenture will be filed by Algonquin on SEDAR on or about the Closing Date.

Redemption prior to maturity may prevent holders from exercising their conversion privilege

The Debentures may be redeemed, at the option of the Corporation and without the consent of holders of Debentures, subject to certain conditions, after the Final Instalment Date and prior to the Maturity Date at a redemption price equal to the principal amount thereof, plus any unpaid interest which accrued prior to the Final Instalment Date, as described under "Details of the Offering – Debentures – Redemption".

The right of holders of Debentures to receive Common Shares will terminate as a result of a redemption by the Corporation of the Debentures as described herein. If a holder of Debentures has its Debentures redeemed by the Corporation following completion of the Acquisition, but prior to conversion by the holder of such Debentures into Common Shares, such holder will not receive any of the benefits which may accrue to shareholders of the Corporation following completion of the Acquisition. In addition, the redemption price of the Debentures may be worth less than the consideration obtained on a conversion of those Debentures by the holder thereof.

Conversion of Debentures following satisfaction of the Approval Conditions can be negatively affected by the market price of the Common Shares

Subject to satisfaction of the Approval Conditions and payment of the final instalment by the holder of an Instalment Receipt on or prior to the Final Instalment Date, such holder may convert its Debentures after the Final Instalment Date but prior to the earlier of the date of redemption or the Maturity Date. The Conversion Price will be $10.60 per Common Share, being a conversion rate of 94.3396 Common Shares per $1,000 principal amount of Debentures, subject to adjustment in certain circumstances. See "Details of the Offering – Debentures – Conversion Right". If the market price of the Common Shares is less than the Conversion Price, the trading price of the Debentures will be negatively impacted. If the market price of the Common Shares is less than the Conversion Price on the date of conversion by a holder, such holder will receive fewer Common Shares on conversion of its Debentures than they would be able to purchase with funds equal to the principal amount of its Debentures.

Interest on Debentures will cease to be payable prior to the Maturity Date

After giving the Final Instalment Notice, Algonquin has the right, but not the obligation, to redeem any outstanding and unconverted Debentures at any time on or after the Final Instalment Date and prior to the Maturity Date, but may choose not to redeem such Debentures. Any unconverted Debentures outstanding on or after the day following the Final Instalment Date will cease to accrue interest. A holder who has not exercised its conversion privilege by such date will be holding a convertible debt security which no longer earns interest.

The likelihood that holders of the Debentures will receive payments owing to them under the terms of the Debentures will depend on the financial health of the Corporation and its creditworthiness

Although Algonquin currently has an investment grade credit rating, there is no assurance the Corporation will have sufficient capital to repay the Debentures in cash on redemption or at the Maturity Date or that it will be able to raise sufficient capital on acceptable terms by the applicable redemption date or the Maturity Date to repay the outstanding Debentures. While Algonquin covenants to maintain readily available capacity under the Revolving Facilities, or have cash on hand together with such available capacity, in an amount at least equal to the net proceeds of the first instalment paid on the closing of the Offering (and on the closing of the Over-Allotment Option, if applicable), in the event of a mandatory redemption, there can be no certainty that the Revolving Facilities, or such cash on hand, will continue to be available at the time of redemption such that Algonquin will not have sufficient funds to repay the Debentures. The risk of default in any payment obligation by Algonquin may increase to the extent that there is a significant decline in the price of the Common Shares.

Debentures are unsecured obligations

The Debentures are unsecured obligations of the Corporation and are not secured by any of its assets or assets of any current or future subsidiaries of the Corporation.

Prevailing yields on similar securities

The prevailing yield on debt securities with comparable maturities will affect the market value of the Debentures. Assuming all other factors remain unchanged, the market value of the Debentures will decline as prevailing yields for similar securities rise, and will increase as prevailing yields for similar securities decline. The market value of the Debentures may also decline after the Debentures cease to accrue interest depending on the value of the underlying Common Shares.

Dilutive effects on shareholders

The issuance of Common Shares on conversion of the Debentures may have a dilutive effect on shareholders of Common Shares of Algonquin and an adverse impact on the price of the Common Shares, which may also adversely impact the price of the Debentures. Potential future offerings by Algonquin of Common Shares or securities convertible into or exchangeable for Common Shares would dilute purchasers acquiring securities under this Prospectus.

Investment eligibility is not guaranteed

The Corporation will endeavour to ensure that the Debentures represented by Instalment Receipts and the Common Shares continue to be qualified investments for Exempt Plans under the Tax Act, although there is no assurance that the conditions prescribed for such qualified investments will be adhered to at any particular time. The Tax Act imposes taxes in respect of the acquisition or holding of non-qualified or prohibited investments by Exempt Plans.

Income tax consequences

The income of the Corporation and its subsidiaries must be computed and is taxed in accordance with Canadian and other applicable tax laws, all of which may be changed in a manner that could adversely affect the holders of Debentures or Common Shares or the Corporation, including the latter's ability to service the Debentures or pay dividends on the Common Shares. There can be no assurance that taxation authorities will accept the tax positions adopted by the Corporation or its subsidiaries, including their determinations of the amounts of income and capital taxes and the reasonableness of inter-company transfer prices, including interest charges, which could materially adversely affect cash positions of the Corporation or its subsidiaries, and holders of Debentures and the Common Shares.

Rights with respect to the Common Shares will arise only if and when the Corporation delivers Common Shares upon conversion of a Debenture

Holders of Debentures will not be entitled to any rights with respect to the Common Shares (including, without limitation, voting rights and rights to receive any dividends or other distributions on the Common Shares, other than extraordinary dividends that the board of directors designates as payable to the holders of the Debentures), but if a holder of Debentures subsequently converts its Debentures into Common Shares, such holder will be subject to all changes affecting the Common Shares. Rights with respect to the Common Shares will arise only if and when the Corporation delivers Common Shares upon conversion of a Debenture and, to a limited extent, under the conversion rate adjustments applicable to the Debentures. For example, in the event that an amendment is proposed to the Corporation's constating documents requiring shareholder approval and the record date for determining the shareholders of record entitled to vote on the amendment occurs prior to delivery of Common

Shares to a holder, such holder will not be entitled to vote on the amendment, although such holder will nevertheless be subject to any changes in the powers or rights of Common Shares that result from such amendment.

If the market price of the Common Shares is less than the Conversion Price, the trading price of the Debentures will be negatively impacted

Subject to satisfaction of the Approval Conditions and payment of the final instalment by the holder of an Instalment Receipt on or prior to the Final Instalment Date, such holder may convert its Debentures after the Final Instalment Date but prior to the earlier of the date of redemption or the Maturity Date. The Conversion Price will be $10.60 per Common Share, being a conversion rate of Common Shares per $1,000 principal amount of Debentures, subject to adjustment in certain circumstances. See "Details of the Offering – Debentures – Conversion Right". If the market price of the Common Shares is less than the Conversion Price, the trading price of the Debentures will be negatively impacted. If the market price of the Common Shares is less than the Conversion Price on the date of conversion by a holder, such holder will receive fewer Common Shares on conversion of its Debentures than they would be able to purchase with funds equal to the principal amount of its Debentures.

Risks Factors Relating to Algonquin

Adverse effect of condemnation by government entities

The Distribution Group's water, wastewater, electricity and natural gas distribution systems could be subject to condemnation or other methods of taking by government entities under certain conditions. Any taking by government entities would legally require 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.

On January 8, 2016, Algonquin acquired the regulated water distribution utility, Park Water, now known as Liberty Utilities (Park Water) Corp. ("**Park Water**") which owns and operates three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in Southern California and Western Montana. Park Water provides, owns and operates a water system in central Los Angeles. Apple Valley Ranchos Water Company, now known as Liberty Utilities (Apple Valley Ranchos Water) Corp. ("**Apple Valley**"), owns and operates a water system in Apple Valley, California. Mountain Water Company ("**Mountain Water**") owns and operates the water system serving the municipality of Missoula, Montana. Mountain Water and Apple Valley are wholly-owned by Park Water.

Mountain Water 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 ultimately take possession of Mountain Water. The City's right to take Mountain Water is currently on appeal before the Montana Supreme Court. The Commissioners' award as part of the condemnation proceeding established the value of Mountain Water's assets at US$88.6 million. It is believed that Mountain Water would also be entitled to reimbursement of attorney's fees plus payment of interest accruing at the rate of 10% per annum since May 2014 under Montana statutes. Accrued interest is currently estimated to be US$14 million. The Commissioners' award of US$88.6 million and the final award ordered by the Missoula District Court also are subject to appeal to the Montana Supreme Court. The City of Missoula has contested payment of interest in the condemnation proceeding. If the City of Missoula ultimately takes possession of Mountain Water, the compensation to be paid by the City of Missoula for such taking will be the value of the utility plus accrued interest and attorney's fees as determined by the Montana court. On December 22, 2015, various developers filed a Petition for Declaratory and Other Relief in Missoula County District Court against Mountain Water and the City of Missoula. The lawsuit pertains to Funded By Others ("**FBO**") contracts between each developer and Mountain Water. Under those FBO contracts, the developers paid for facilities to provide water service. Mountain Water agreed to refund those developer advances under the FBO contracts over a 40 year period. These FBO contracts represent a liability of US$22 million on the balance sheet of Mountain Water. While there is no allegation of breach by Mountain Water under the FBO contracts, the developers are seeking to enforce these refunds should the utility be transferred to the city. That lawsuit is ongoing and is in the early stages of litigation. In addition, the Montana Public Service Commission ("**Montana PSC**") has asserted that the indirect change of control of Mountain Water required its approval and is, therefore, investigating potential changes to the rates of Mountain Water. Montana PSC has also expressed an intention to seek penalties against Mountain Water. The Montana PSC has acknowledged that it has no express authority over the acquisition transaction under statute, but has asserted that such authority should be implied. These matters are in the early stages.

On January 8, 2016, the Town of Apple Valley filed an eminent domain complaint against Apple Valley. In California, parties to a condemnation case typically agree for the case to be bifurcated into two phases. The first phase will determine the necessity of the taking. The second phase will involve the valuation of the utility assets. If the Town of Apple Valley is successful in the right to take proceeding, a second phase will be held to determine the fair market value of Apple Valley. At present, a trial setting conference has been set for July 7, 2016. The matter is expected to take two to three years to resolve. The condemnation action has potential financial implications for Liberty Utilities depending on the outcome of the condemnation process. In the event that the Town of Apple Valley prevails in the necessity phase of the condemnation case, the financial impact of the condemnation case will depend on the ultimate determination of the fair market value of Apple Valley's assets by a jury, along with a determination of interest and attorney's fees by the court.

Construction and Development Risk

At any given time the Corporation is involved in various construction activities. The Generation Group actively engages in the development and construction of new power generation facilities and has a current pipeline of projects either currently in construction or in development of $1.2 billion (mainly renewable solar and wind projects). The Transmission Group, in partnership with Kinder Morgan, is actively engaged in the development and construction of two pipelines. Furthermore, each of the Corporation's business segments may occasionally undertake construction activities as part of normal course maintenance activities. 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, unfavourable permitting results or delays emanating from Municipal, State, Provincial or Federal agency interface, construction delays or cost overruns, currency fluctuations affecting the cost of major capital components such as turbines, equipment performance outside of expectations, land owner disputes and construction disputes which may result in the registering of liens on the Corporation's projects.

The Corporation mitigates these risks through its due diligence processes, sound project management principles, active deployment of risk analysis, management and mitigation tools and appropriate contingency plans and reserves.

AUDITORS

Ernst & Young LLP, Chartered Professional Accountants, Toronto, Ontario, are the auditors of Algonquin. Ernst & Young LLP have confirmed they are independent with respect to Algonquin within the meaning of the Rules of Professional Conduct of Chartered Professional Accountants of Ontario (registered name of The Institute of Chartered Accountants of Ontario).

The auditors of Empire are PricewaterhouseCoopers LLP, in St. Louis, Missouri. PricewaterhouseCoopers LLP is an independent registered public accounting firm that audited Empire's audited consolidated financial statements as at December 31, 2014 and December 31, 2013 included in this Prospectus.

LEGAL MATTERS

Certain legal matters relating to the Offering will be passed upon on behalf of the Corporation and the Selling Debenture holder by Blake, Cassels & Graydon LLP and on behalf of the Underwriters by Bennett Jones LLP, Toronto. At the date hereof, partners and associates of each of Blake, Cassels & Graydon LLP and Bennett Jones LLP own beneficially, directly or indirectly, less than 1% of any securities of the Corporation or any associate or affiliate of the Corporation.

TRANSFER AGENT AND REGISTRAR

CST Trust Company of Canada is the registrar and transfer agent of the Corporation. Registers for the registration and transfer of the securities in registered form of Algonquin are kept at the principal offices of CST Trust Company of Canada in the City of Toronto, Ontario.

ENFORCEABILITY OF CERTAIN CIVIL LIABILITIES

Masheed Saidi and Dilek Samil, directors of the Corporation, both reside outside of Canada. Each of Ms. Saidi and Ms. Samil has appointed Algonquin Power & Utilities Corp., 354 Davis Road, Oakville, Ontario, L6J 2X1 as her agent for service of process in Canada.

Purchasers are advised that it may not be possible for investors to enforce judgments obtained in Canada against any person or company that is incorporated, continued or otherwise organized under the laws of a foreign jurisdiction or resides outside of Canada, even if the party has appointed an agent for service of process.

PURCHASERS' STATUTORY RIGHTS

Securities legislation in certain of the provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus and any amendment. In several of the provinces, the securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, revisions of the price or damages if the prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that the remedies for rescission, revisions of the price or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province for the particulars of these rights or consult with a legal advisor.

Original purchasers of Debentures will have a contractual right of rescission against Algonquin following the conversion of such Debentures in the event that this Prospectus or any amendment thereto contains a misrepresentation. The contractual right of rescission will entitle such original purchasers to receive from Algonquin, upon surrender of the Common Shares issued upon conversion of such Debentures, the amount paid for such Debentures, provided that the right of rescission is exercised within 180 days from the date of the purchase of such Debentures under this Prospectus.

In an offering of Debentures represented by Instalment Receipts, investors are cautioned that the statutory right of action for damages for a misrepresentation contained in this Prospectus is limited, in certain provincial securities legislation, to the price at which the Debentures represented by Instalment Receipts are offered to the public under the prospectus offering. This means that, under the securities legislation of certain provinces, if the purchaser pays additional amounts upon conversion of the security, those amounts may not be recoverable under the statutory right of action for damages that applies in those provinces. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province for the particulars of this right of action for damages or consult with a legal adviser.

GLOSSARY OF TERMS

In this Prospectus, unless the context otherwise requires, the following terms have the meanings set forth below.

"**1933 Act**" has the meaning ascribed thereto under the heading "Plan of Distribution".

"**Acquisition**" means the acquisition by AcquisitionCo of Empire pursuant to the terms of the Acquisition Agreement.

"**Acquisition Agreement**" means the Agreement and Plan of Merger dated February 9, 2016 among AcquisitionCo, Merger Sub and Empire.

"**Acquisition Credit Agreements**" has the meaning ascribed thereto under the heading "Financing the Acquisition – Acquisition Credit Facilities".

"**Acquisition Credit Facilities**" has the meaning ascribed thereto under the heading "Financing the Acquisition – Acquisition Credit Facilities".

"**Acquisition-Related Expenses**" means the estimated non-recurring costs, including related income tax effects and any governmental and other imposed costs that may be incurred to consummate the Acquisition. Such costs, which will be fully expensed when incurred in accordance with U.S. GAAP, include but are not limited to fees associated with financial advisory, consulting, accounting, tax, legal and other professional services, bridge facility commitment fees, costs associated with change of control and integration, out-of-pocket costs and other costs of a non-recurring nature.

"**AcquisitionCo**" means Liberty Utilities (Central) Co., a wholly-owned indirect subsidiary of Algonquin.

"**Adjusted EBITDA**" means adjusted earnings before interest, income taxes, depreciation and amortization.

"**Adverse Recommendation Change**" has the meaning ascribed thereto under the heading "The Acquisition Agreement – No Solicitation: Empire's Board of Directors Recommendation".

"**AFUDC**" means allowance for funds used during construction and represents the cost of financing regulated construction projects and is capitalized to the cost of property, plant and equipment, where permitted by the regulator.

"**AIF**" has the meaning ascribed thereto under the heading "Documents Incorporated by Reference".

"**Algonquin**" or the "**Corporation**" means Algonquin Power & Utilities Corp.

"**Annual MD&A**" has the meaning ascribed thereto under the heading "Documents Incorporated by Reference".

"**AQCS**" means Asbury Air Quality Control System.

"**Apple Valley**" means Apple Valley Ranchos Water Company, now known as Liberty Utilities (Apple Valley Ranchos Water) Corp.

"**Approval Conditions**" has the meaning ascribed thereto under the heading "Details of the Offering".

"**APSC**" means the Arkansas Public Service Commission.

"**Bank Indebtedness**" has the meaning ascribed thereto under the heading "Relationship between Algonquin, the Selling Debentureholder and Certain Underwriters".

"**bcf**" means billion cubic feet.

"**Board of Directors**" means the board of directors of Algonquin.

“**Book-Entry Only System**” has the meaning ascribed thereto under the heading “Details of the Offering – Instalment Receipts – Book-Entry Only System”.

“**CAGR**” means compound annual growth rate.

“**CBCA**” means the *Canada Business Corporations Act*.

“**CDS**” means CDS Clearing and Depository Services Inc.

“**CDS Participant**” means a participant in CDS.

“**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 *Defense Production Act of 1950*, as amended (“**DPA**”), with respect to the transactions contemplated by the Acquisition 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 the Acquisition Agreement or (ii) having received a report from CFIUS requesting the President’s decision, the President has not taken any action after fifteen days from the date the President received such report from CFIUS.

“**Closing Date**” means the closing of the Offering, which is expected to take place on or about March 1, 2016.

“**Common Shares**” means the common shares in the capital of Algonquin.

“**Conversion Price**” means $10.60 per Common Share, being a conversion rate of 94.3396 Common Shares per $1,000 principal amount of Debentures, subject to adjustment in certain events.

“**Counsel**” has the meaning ascribed thereto under the heading “Certain Canadian Federal Income Tax Considerations”.

“**Custodian**” has the meaning ascribed thereto under the heading “Details of the Offering – Instalment Receipts”.

“**DBRS**” means DBRS Limited.

“**Debentures**” means 5.00 % convertible unsecured subordinated debentures of Algonquin offered pursuant to this Prospectus.

“**Defaulting Holder**” has the meaning ascribed thereto under the heading “Details of the Offering – Instalment Receipts”.

“**Director Stock Units**” has the meaning ascribed thereto under the heading “The Acquisition Agreement – The Merger Consideration”.

“**Distribution Group**” means the Corporation’s Distribution Business Group.

“**Dividend Reinvestment Plan**” has the meaning ascribed thereto under the heading “Prior Sales”.

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

“**EDE Mortgage**” means the Indenture of Mortgage and Deed of Trust of The Empire District Electric Company dated as of September 1, 1944, as amended and supplemented.

“**EDG Mortgage**” means the Indenture of Mortgage and Deed of Trust of The Empire District Gas Company dated as of June 1, 2006, as amended and supplemented.

“**Empire**” means The Empire District Electric Company and its subsidiaries, and references to individual subsidiaries of The Empire District Electric Company refer to that company and its respective subsidiaries.

"**Empire Acquisition Agreement**" means any letter of intent, memorandum of understanding, agreement in principle, agreement or commitment constituting, or that would reasonably be expected to lead to, any Takeover Proposal, or requiring, or that would reasonably be expected to cause, Empire to abandon or terminate the Acquisition Agreement.

"**Empire Material Adverse Effect**" has the meaning ascribed thereto under the heading "The Acquisition Agreement – Closing Conditions".

"**Empire Shareholder Approval**" has the meaning ascribed thereto under the heading "The Acquisition Agreement – Closing Conditions".

"**End Date**" has the meaning ascribed thereto under the heading "The Acquisition Agreement – Termination".

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

"**Exempt Plans**" has the meaning ascribed thereto under the heading "Eligibility for Investment".

"**FCC**" means the United States Federal Communications Commission.

"**FERC**" means the United States Federal Energy Regulatory Commission.

"**Final Instalment Date**" has the meaning ascribed thereto under the heading "Details of the Offering".

"**Final Instalment Notice**" has the meaning ascribed thereto under the heading "Details of the Offering".

"**Fitch**" means Fitch Ratings.

"**GDP**" means gross domestic product.

"**Generation Group**" means the Corporation's Generation Business Group.

"**Holder**" has the meaning ascribed thereto under the heading "Certain Canadian Federal Income Tax Considerations".

"**HSR Act**" means the *Hart-Scott-Rodino Antitrust Improvements Act of 1976*, as amended.

"**Indenture**" has the meaning ascribed thereto under the heading "Details of the Offering – Debentures".

"**Instalment Receipt Agreement**" has the meaning ascribed thereto under the heading "Details of the Offering – Instalment Receipts".

"**Instalment Receipts**" means the instalment receipts representing beneficial ownership of the Debentures.

"**Intervening Event**" has the meaning ascribed thereto under the heading "The Acquisition Agreement – No Solicitation: Empire's Board of Directors Recommendation".

"**KCC**" means the State Corporation Commission of the State of Kansas.

"**KCP&L**" means Kansas City Power and Light Company.

"**KV**" means kilovolt.

"**kWh**" means kilowatt-hour.

"**Liberty Utilities**" means Liberty Utilities Co.

"**Kinder Morgan"** means Kinder Morgan, Inc.

"**Make-Whole Payment**" has the meaning ascribed thereto on the cover page.

“**Marketing Materials**” has the meaning ascribed thereto under the heading “Documents Incorporated by Reference”.

“**Market Path Project**” has the meaning ascribed thereto under the heading “Algonquin – Transmission Group”.

“**Market Price**” means the weighted average trading price of the Common Shares on the TSX for the 20 consecutive trading days ending five trading days preceding the Maturity Date.

“**MATS**” means the Mercury Air Toxic Standards.

“**Maturity Date**” means March 31, 2026.

“**Merger**” has the meaning ascribed thereto under the heading “The Acquisition Agreement – The Merger”.

“**Merger Sub**” means Liberty Sub Corp., a direct wholly-owned subsidiary of AcquisitionCo.

“**Moody’s**” means Moody’s Investors Service, Inc.

“**MPSC**” means the Missouri Public Service Commission.

“**MW**” means megawatts.

“**MWh**” means megawatt-hours.

“**Mountain Water**” means Mountain Water Company.

“**Northeast Expansion LLC**” has the meaning ascribed thereto under the heading “Algonquin – Transmission Group”.

“**Northeast Supply Pipeline LLC**” has the meaning ascribed thereto under the heading “Algonquin –Transmission Group”.

“**NYSE**” means the New York Stock Exchange.

“**OCC**” means the Oklahoma Corporation Commission.

“**Offering**” means the offering of Debentures represented by Instalment Receipts pursuant to this Prospectus.

“**Offering Price**” has the meaning ascribed thereto under the heading “Plan of Distribution”.

“**OPEB**” means Other Postretirement Benefits.

“**Over-Allotment Option**” means an option to purchase additional Debentures represented by Instalment Receipts equal to up to 15% of the aggregate principal amount of Debentures, as more fully described on the cover page.

“**Park Water**” means Park Water Company, now known as Liberty Utilities (Park Water) Corp.

“**PBR**” means Performance Based Ratemaking.

“**Performance-Based RSAs**” means performance based restricted stock awards.

“**PGA**” means purchased gas adjustment.

“**Plum Point**” means Plum Point Energy Station.

“**PPA**” means a power purchase agreement.

“**Proposed Amendments**” has the meaning ascribed thereto under the heading “Certain Canadian Federal Income Tax Considerations”.

"**Prospectus**" means this preliminary short form prospectus dated February 15, 2016.

"**Q3 MD&A**" has the meaning ascribed thereto under the heading "Documents Incorporated by Reference".

"**REC**" means Renewable Energy Credit.

"**Representatives**" has the meaning ascribed thereto under the heading "The Acquisition Agreement – No Solicitation: Empire's Board of Directors Recommendation".

"**Revolving Facilities**" means the existing revolving credit facilities in favour of Algonquin (on a consolidated basis).

"**S&P**" means Standard & Poor's Ratings Services.

"**SEC**" means the U.S. Securities and Exchange Commission.

"**Securities**" has the meaning ascribed thereto under the heading "Certain Canadian Federal Income Tax Considerations".

"**SEDAR**" means the System for Electronic Document Analysis and Retrieval.

"**Selling Debentureholder**" means Liberty Utilities (Canada) Corp., a direct wholly-owned subsidiary of Algonquin.

"**Senior Indebtedness**" has the meaning ascribed thereto under the heading "Details of the Offering – Debentures – Subordination".

"**Series A Shares**" has the meaning ascribed thereto under the heading "Share Capital of Algonquin".

"**Series C Shares**" has the meaning ascribed thereto under the heading "Share Capital of Algonquin".

"**Series D Shares**" has the meaning ascribed thereto under the heading "Share Capital of Algonquin".

"**SLCC**" means the State Line Combined Cycle.

"**Southern Star**" means Southern Star Central Pipeline, Inc.

"**SPP**" means Southwest Power Pool.

"**SPP IM**" means Southwest Power Pool Integrated Marketplace.

"**SPP RTO**" means Southwest Power Pool Regional Transmission Organization.

"**State Commissions**" means the Arkansas Public Service Commission, the Kansas Corporation Commission, the Missouri Public Service Commission and the Oklahoma Corporation Commission.

"**Superior Proposal**" has the meaning ascribed thereto under the heading "The Acquisition Agreement – No Solicitation: Empire's Board of Directors Recommendation".

"**Supply Path Project**" has the meaning ascribed thereto under the heading "Algonquin – Overview – Transmission Group".

"**SWPA**" means Southwest Power Administration.

"**Takeover Proposal**" has the meaning ascribed thereto under the heading "The Acquisition Agreement – No Solicitation: Empire's Board of Directors Recommendation".

"**Tax Act**" means the *Income Tax Act* (Canada) and the regulations thereunder, as amended from time to time.

"**Time-Vested RSAs**" has the meaning ascribed thereto under the heading "The Acquisition Agreement – The Merger Consideration".

"**Transmission Group**" means the Corporation's Transmission Business Group.

"**Trustee**" has the meaning ascribed thereto under the heading "Details of the Offering – Debentures".

"**TSX**" means the Toronto Stock Exchange.

"**U.S.**" means the United States.

"**U.S. dollars**" or "**US$**" means the lawful currency of the U.S.

"**U.S. GAAP**" means Generally Accepted Accounting Principles in the United States.

"**Underwriters**" means CIBC World Markets Inc., Scotia Capital Inc., BMO Nesbitt Burns Inc., National Bank Financial Inc., RBC Dominion Securities Inc., TD Securities Inc., Desjardins Securities Inc., Raymond James Ltd., J.P. Morgan Securities Canada Inc., Wells Fargo Securities Canada, Ltd., Industrial Alliance Securities Inc., Canaccord Genuity Corp. and Cormark Securities Inc.

"**Underwriting Agreement**" has the meaning ascribed thereto under the heading "Plan of Distribution".

INDEX TO FINANCIAL STATEMENTS

THE EMPIRE DISTRICT ELECTRIC COMPANY

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of The Empire District Electric Company:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, common stockholders' equity and cash flows present fairly, in all material respects, the financial position of The Empire District Electric Company and its subsidiaries at December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements 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 the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

St. Louis, Missouri
February 20, 2015

THE EMPIRE DISTRICT ELECTRIC COMPANY
Consolidated Balance Sheets

	December 31, 2014	2013
	($-000's)	
Assets		
Plant and property, at original cost:		
Electric	$ 2,420,824	$ 2,219,605
Gas	79,364	72,834
Other	41,394	39,902
Construction work in progress	112,097	152,330
	2,653,679	2,484,671
Accumulated depreciation and amortization	743,407	732,737
	1,910,272	1,751,934
Current assets:		
Cash and cash equivalents	2,105	3,475
Restricted cash	4,726	2,872
Accounts receivable – trade, net of allowance of $1,021 and $1,025, respectively	45,444	50,137
Accrued unbilled revenues	25,945	26,694
Accounts receivable – other	41,256	13,101
Fuel, materials and supplies	57,799	48,811
Prepaid expenses and other	27,879	15,954
Unrealized gain in fair value of derivative contracts	3,901	2,469
Regulatory assets	10,752	7,743
	219,807	171,256
Noncurrent assets and deferred charges:		
Regulatory assets	209,717	169,333
Goodwill	39,492	39,492
Unamortized debt issuance costs	8,821	8,826
Unrealized gain in fair value of derivative contracts	-	41
Other	2,147	4,163
	260,177	221,855
Total assets	**$ 2,390,256**	**$ 2,145,045**

(Continued)

The accompanying notes are an integral part of these consolidated financial statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY
Consolidated Balance Sheets

	December 31, 2014	December 31, 2013
	($-000's)	
Capitalization and liabilities		
Common stock, $1 par value, 100,000,000 shares authorized, 43,479,186 and 43,044,185 shares issued and outstanding, respectively	$ 43,479	$ 43,044
Capital in excess of par value	649,543	639,525
Retained earnings	90,276	67,554
Total common stockholders' equity	783,298	750,123
Long-term debt (net of current portion)		
Obligations under capital lease	3,875	4,167
First mortgage bonds and secured debt	697,615	637,578
Unsecured debt	101,699	101,683
Total long-term debt	803,189	743,428
Total long-term debt and common stockholders' equity	1,586,487	1,493,551
Current liabilities:		
Accounts payable and accrued liabilities	83,420	71,375
Current maturities of long-term debt	292	274
Short-term debt	44,000	4,000
Regulatory liabilities	7,898	5,681
Customer deposits	13,747	12,543
Interest accrued	6,565	6,352
Unrealized loss in fair value of derivative contracts	6,469	1,889
Taxes accrued	3,380	3,386
Other current liabilities	356	299
	166,127	105,799
Commitments and contingencies (Note 11)		
Noncurrent liabilities and deferred credits:		
Regulatory liabilities	128,471	132,012
Deferred income taxes	377,452	324,266
Unamortized investment tax credits	18,367	18,431
Pension and other postretirement benefit obligations	93,863	51,405
Unrealized loss in fair value of derivative contracts	3,243	2,799
Other	16,246	16,782
	637,642	545,695
Total capitalization and liabilities	**$ 2,390,256**	**$ 2,145,045**

The accompanying notes are an integral part of these consolidated financial statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY
Consolidated Statements of Income

	Year Ended December 31, 2014	2013	2012
	(000's, except per share amounts)		
Operating revenues:			
Electric	$ 592,491	$ 536,413	$ 510,653
Gas	51,842	50,041	39,849
Other	7,997	7,876	6,595
	652,330	594,330	557,097
Operating revenue deductions:			
Fuel and purchased power	215,086	175,406	178,896
Cost of natural gas sold and transported	27,025	25,795	18,633
Regulated operating expenses	110,691	105,333	94,371
Other operating expenses	2,987	3,142	2,730
Maintenance and repairs	46,775	40,873	40,444
Loss on plant disallowance	86	2,409	-
Depreciation and amortization	73,185	69,306	60,447
Provision for income taxes	39,398	37,465	34,096
Other taxes	37,098	34,938	31,259
	552,331	494,667	460,876
Operating income	99,999	99,663	96,221
Other income and (deductions):			
Allowance for equity funds used during construction	6,420	3,853	1,147
Interest income	51	566	972
Benefit/(provision) for other income taxes	178	(27)	(63)
Other – non-operating expense, net	(1,302)	(1,218)	(1,910)
	5,347	3,174	146
Interest charges:			
Long-term debt	40,637	40,354	40,192
Short-term debt	113	60	187
Allowance for borrowed funds used during construction	(3,497)	(2,087)	(781)
Other	990	1,065	1,088
	38,243	39,392	40,686
Net income	**$ 67,103**	**$ 63,445**	**$ 55,681**
Weighted average number of common shares outstanding - basic	43,291	42,781	42,257
Weighted average number of common shares outstanding - diluted	43,314	42,803	42,284
Total earnings per weighted average share of common stock – basic and diluted	**$ 1.55**	**$ 1.48**	**$ 1.32**
Dividends declared per share of common stock	**$ 1.025**	**$ 1.005**	**$ 1.000**

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, 2011	$ 41,978	$ 618,304	$ 33,707	$ 693,989
Net income			55,681	55,681
Stock/stock units issued through:				
Stock purchase and reinvestment plans	506	9,895		10,401
Dividends declared			(42,273)	(42,273)
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

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,		
	2014	**2013** ($-000's)	**2012**
Operating activities:			
Net income	$ 67,103	$ 63,445	$ 55,681
Adjustments to reconcile net income to cash flows from operating activities:			
Depreciation and amortization including regulatory items	82,754	71,734	71,160
Pension and other postretirement benefit costs, net of contributions	1,973	(1,888)	1,689
Deferred income taxes and unamortized investment tax credit, net	41,693	28,272	31,899
Allowance for equity funds used during construction	(6,420)	(3,853)	(1,147)
Stock compensation expense	4,057	2,984	2,285
Loss on plant disallowance	86	2,409	-
Non-cash loss on derivatives	1,245	14	4,174
Regulatory reversal of gain on sale of assets	44	1,236	-
Other	-	-	(16)
Cash flows impacted by changes in:			
Accounts receivable and accrued unbilled revenues	(24,174)	(14,312)	(688)
Fuel, materials and supplies	(8,121)	10,891	369
Prepaid expenses, other current assets and deferred charges	(6,051)	689	(9,238)
Accounts payable and accrued liabilities	1,141	(880)	(1,297)
Asset retirement obligation	(1,326)	(734)	-
Interest, taxes accrued and customer deposits	1,411	1,386	875
Other liabilities and other deferred credits	(4,192)	(3,942)	3,360
Net cash provided by operating activities	151,223	157,451	159,106

(Continued)

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, 2014	2013 ($-000's)	2012
Investing activities:			
Capital expenditures – regulated	$ (211,429)	$ (152,524)	$ (134,272)
Capital expenditures and other investments – non-regulated	(1,998)	(2,259)	(2,670)
Restricted cash	(1,854)	1,485	(1)
Total net cash used in investing activities	(215,281)	(153,298)	(136,943)
Financing activities:			
Proceeds from first mortgage bonds, net	60,000	150,000	88,000
Long-term debt issuance costs	(651)	(1,879)	(1,074)
Proceeds from issuance of common stock, net of issuance costs	7,994	9,546	8,114
Repayment of first mortgage bonds	-	-	(88,029)
Redemption of senior notes	-	(98,000)	-
Net short-term borrowings (repayments)	40,000	(20,000)	12,000
Dividends	(44,381)	(43,006)	(42,273)
Other	(274)	(714)	(934)
Net cash provided by / (used) in financing activities	62,688	(4,053)	(24,196)
Net increase (decrease) in cash and cash equivalents	(1,370)	100	(2,033)
Cash and cash equivalents, beginning of year	3,475	3,375	5,408
Cash and cash equivalents, end of year	$ 2,105	$ 3,475	$ 3,375

	2014	2013	2012
Supplemental cash flow information:			
Interest paid	$ 40,127	$ 39,033	$ 38,802
Income taxes (refunded) paid, net of refund	23,103	10,584	(592)
Supplementary non-cash investing activities:			
Change in accrued additions to property, plant and equipment not reported above	$ 9,427	$ 5,420	$ 9,345
Capital lease obligations for purchase of new equipment	-	-	-

The accompanying notes are an integral part of these consolidated financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

We operate our businesses as three segments: electric, gas and other. The Empire District Electric Company (EDE), a Kansas corporation organized in 1909, is an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. As part of our electric segment, we also provide water service to three towns in Missouri. The Empire District Gas Company (EDG) is our wholly-owned subsidiary engaged in the distribution of natural gas in Missouri. Our other segment consists of our fiber optics business. See Note 12. Our gross operating revenues in 2014 were derived as follows:

Electric segment sales*	90.8%
Gas segment sales	8.0
Other segment sales	1.2

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

The utility portions of our business are subject to regulation by the Missouri Public Service Commission (MPSC), the State Corporation Commission of the State of Kansas (KCC), the Corporation Commission of Oklahoma (OCC), the Arkansas Public Service Commission (APSC) and the Federal Energy Regulatory Commission (FERC). Our accounting policies are in accordance with the ratemaking practices of the regulatory authorities and conform to generally accepted accounting principles as applied to regulated public utilities.

Our electric operations serve approximately 170,000 customers as of December 31, 2014, and the 2014 electric operating revenues were derived as follows:

Customer	% of revenue
Residential	40.0%
Commercial	29.2
Industrial	14.4
Wholesale on-system	3.8
Wholesale off-system	7.6
Miscellaneous sources, primarily public authorities	2.6
Other electric revenues	2.4

Our retail electric revenues for 2014 by jurisdiction were as follows:

Jurisdiction	% of revenue
Missouri	89.7%
Kansas	4.8
Arkansas	2.7
Oklahoma	2.8

Our gas operations serve approximately 43,500 customers as of December 31, 2014, and the 2014 gas operating revenues were derived as follows:

Customer	% of revenue
Residential	63.4%
Commercial	26.3
Industrial	1.0
Other	9.3

Basis of Presentation

The consolidated financial statements include the accounts of EDE, EDG, and our other subsidiaries. The consolidated entity is referred to throughout as "we" or the "Company". All intercompany balances and transactions have been eliminated in consolidation. See Note 12 for additional information regarding our three segments.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles (GAAP) 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 the financial statements. Estimates also affect the reported amounts of revenues and expenses during the period. Areas in the financial statements significantly affected by estimates and assumptions include unbilled utility revenues, collectability of accounts receivable, depreciable lives, asset impairment and goodwill impairment evaluations, employee benefit obligations, contingent liabilities, asset retirement obligations, the fair value of stock based compensation, tax provisions and derivatives. Actual amounts could differ from those estimates.

Accounting for the Effects of Regulation

In accordance with the Accounting Standard Codification (ASC) guidance for regulated operations, our financial statements reflect ratemaking policies prescribed by the regulatory commissions having jurisdiction over our regulated generation and other utility operations (the MPSC, the KCC, the OCC, the APSC and the FERC).

We record a regulatory asset for all or part of an incurred cost that would otherwise be charged to expense in accordance with the ASC guidance for regulated operations which says that an asset should be recorded if it is probable that future revenue in an amount at least equal to the capitalized cost will be allowable for costs for rate making purposes and the current available evidence indicates that future revenue will be provided to permit recovery of the cost. This guidance also indicates that a liability should be recorded when a regulator has provided current recovery for a cost that is expected to be incurred in the future. We follow this guidance for incurred costs or credits that are subject to future recovery from or refund to our customers in accordance with the orders of our regulators.

Historically, all costs of this nature, which are determined by our regulators to have been prudently incurred, have been recoverable through rates in the course of normal ratemaking procedures. Regulatory assets and liabilities are ratably amortized through a charge or credit, respectively, to earnings while being recovered in revenues and fully recognized if and when it is no longer probable that such amounts will be recovered through future revenues. We generally include amortization of regulatory assets and liabilities in the depreciation and amortization line of our statement of cash flows. We continually assess the recoverability of our regulatory assets. Although we believe it unlikely, should retail electric competition legislation be passed in the states we serve, we may determine that we no longer meet the criteria set forth in the ASC guidance for regulated operations with respect to continued recognition of some or all of the regulatory assets and liabilities. Any regulatory changes that would require us to discontinue application of this guidance based upon competitive or other events may also impact the valuation of certain utility plant investments. Impairment of regulatory assets or utility plant investments could have a material adverse effect on our financial condition and results of operations. (See Note 3 for further discussion of regulatory assets and liabilities).

Revenue Recognition

For our utility operations, we use cycle billing and accrue estimated, but unbilled, revenue for services provided between the last bill date and the period end date. Unbilled revenues represent the estimate of receivables for energy and natural gas services delivered, but not yet billed to customers. The accuracy of our unbilled revenue estimate is affected by factors including fluctuations in energy demands, weather, line losses and changes in the composition of customer classes. During 2012, we recorded an increase in electric unbilled revenues as a result of certain changes to the assumptions used in determining estimated unbilled revenues.

Municipal Franchise Taxes

Municipal franchise taxes are collected for and remitted to their respective entities and are included in operating revenues and other taxes in the Consolidated Statements of Income. Municipal franchise taxes of $11.8 million, $11.2 million and $10.4 million were recorded for each of the years ended December 31, 2014, 2013 and 2012, respectively.

Accounts Receivable

Accounts receivable are recorded at the tariffed rates for customer usage, including applicable taxes and fees and do not bear interest. We review the outstanding accounts receivable monthly, as well as the bad debt write-offs experienced in the past, and establish an allowance for doubtful accounts. Account balances are charged off against the allowance when management determines it is probable the receivable will not be recovered.

Property, Plant & Equipment

The costs of additions to utility property and replacements for retired property units are capitalized. Costs include labor, material, an allocation of general and administrative costs, and an allowance for funds used during construction (AFUDC). The original cost of units retired or disposed of and the costs of removal are charged to accumulated depreciation, unless the removed property constitutes an operating unit or system. In this case a gain or loss is recognized upon the disposal of the asset. Maintenance expenditures and the removal of minor property items are charged to income as incurred. A liability is created for any additions to electric or gas utility property that are paid for by advances from developers. For a period of five years we refund to the developer a pro rata amount of the original cost of the extension for each new customer added to the extension. Non-refundable payments at the end of the five year period are applied as a reduction to the cost of the plant in service. The liability as of December 31, 2014 and 2013 was $1.9 million and $4.2 million, respectively.

Depreciation

Provisions for depreciation are computed at straight-line rates in accordance with GAAP consistent with rates approved by regulatory authorities. These rates are applied to the various classes of utility assets on a composite basis. Provisions for depreciation for our other segment are computed at straight-line rates over the estimated useful life of the properties (See Note 2 for additional details regarding depreciation rates).

As of December 31, 2014 and 2013, we had recorded accrued cost of removal of $82.8 million and $81.3 million, respectively, for our electric operating segment. This represents an estimated cost of dismantling and removing plant from service upon retirement, accrued as part of our depreciation rates. We accrue cost of removal in depreciation rates for mass property (including transmission, distribution and general plant assets). These accruals are not considered an asset retirement obligation under the guidance provided on asset retirement obligations within the ASC. We reclassify the accrued cost of dismantling and removing plant from service upon retirement from accumulated depreciation to a regulatory liability. We have a similar cost of removal regulatory liability for our gas operating segment. This amount at December 31, 2014 and 2013 was $7.7 million and $7.2 million, respectively. These amounts are net of our actual cost of removal expenditures.

Asset Retirement Obligation

We record the estimated fair value of legal obligations associated with the retirement of tangible long-lived assets in the period in which the liabilities are incurred and capitalize a corresponding amount as part of the book value of the related long-lived asset. In subsequent periods, we are required to adjust asset retirement obligations based on changes in estimated fair value, and the corresponding increases in asset book values are depreciated over the useful life of the related asset. Uncertainties as to the probability, timing or cash flows associated with an asset retirement obligation affect our estimate of fair value.

We have identified asset retirement obligations associated with the future removal of certain river water intake structures and equipment at the Iatan Power Plant, in which we have a 12% ownership. We also have a solid waste land fill at the Plum Point Energy Station, and asset retirement obligations associated with the removal of asbestos located at the Riverton and Asbury Plants. As a result of the fuel use transition from coal to natural gas at the

Riverton Power Plant, the closure of the Riverton ash landfill was completed, and the related asset retirement obligation was settled during 2014 (Note 11).

In addition, we have a liability for the removal and disposal of Polychlorinated Biphenyls (PCB) contaminants associated with our transformers and substation equipment. These liabilities have been estimated based upon either third party costs or historical review of expenditures for the removal of similar past liabilities. The potential costs of these future expenditures are based on engineering estimates of third party costs to remove the assets in satisfaction of the associated obligations. This liability will be accreted over the period up to the estimated settlement date.

All of our recorded asset retirement obligations have been estimated as of the expected retirement date, or settlement date, and have been discounted using a credit adjusted risk-free rate ranging from 4.5% to 5.52% depending on the settlement date. Revisions to these liabilities could occur due to changes in the cost estimates, anticipated timing of settlement or federal or state regulatory requirements. During 2014 the liability for asbestos at the Riverton Power Plant was re-evaluated, and during 2012 the liabilities for both the ash landfill at the Riverton Power Plant, and PCB contaminants were re-evaluated. Changes in the cost estimates and timing resulted in cash flow revisions for these liabilities.

The balances at the end of 2013 and 2014 are shown below.

(000's)	Liability Balance 12/31/13	Liabilities Recognized	Liabilities Settled	Accretion	Cash Flow Revisions	Liability Balance at 12/31/14
Asset Retirement Obligation	$ 4,190	$ -	$ (1,175)	$ 172	$ 1,660	$ 4,847

(000's)	Liability Balance 12/31/12	Liabilities Recognized	Liabilities Settled	Accretion	Cash Flow Revisions	Liability Balance at 12/31/13
Asset Retirement Obligation	$ 4,711	$ -	$ (734)	$ 213	$ -	$ 4,190

Upon adoption of the standards on the retirement of long lived assets and conditional asset retirement obligations, we recorded a liability and regulatory asset because we expect to recover these costs of removal in electric and gas rates either through depreciation accruals or direct expenses. We also defer the liability accretion and depreciation expense as a regulatory asset. At December 31, 2014 and 2013, our regulatory assets relating to asset retirement obligations totaled $5.1 million and $4.7 million, respectively.

Also as noted previously under property, plant and equipment, we reclassify the accrued cost of dismantling and removing plant from service upon retirement, which is not considered an asset retirement obligation under this guidance, from accumulated depreciation to a regulatory liability. This balance sheet reclassification has no impact on results of operations.

Allowance for Funds Used During Construction

As provided in the FERC regulatory Uniform System of Accounts, utility plant is recorded at original cost, including an allowance for funds used during construction (AFUDC) when first placed in service. The AFUDC is a utility industry accounting practice whereby the cost of borrowed funds and the cost of equity funds applicable to construction programs are capitalized as a cost of construction. This accounting practice offsets the effect on earnings of the cost of financing current construction, and treats such financing costs in the same manner as construction charges for labor and materials.

AFUDC does not represent current cash income. Recognition of this item as a cost of utility plant is in accordance with regulatory rate practice under which such plant costs are permitted as a component of rate base and the provision for depreciation.

In accordance with the methodology prescribed by the FERC, we utilized aggregate rates (on a before-tax basis) of 6.6% for 2014, 7.3% for 2013, and 5.6% for 2012, compounded semi-annually.

Asset Impairments (excluding goodwill)

We review long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. To the extent that certain assets may be impaired, analysis is performed based on undiscounted forecasted cash flows to assess the recoverability of the assets and, if necessary, the fair value is determined to measure the impairment amount. None of our assets were impaired as of December 31, 2014 and 2013.

Goodwill

As of December 31, 2014, the consolidated balance sheet included $39.5 million of goodwill. All of this goodwill was derived from our gas acquisition and recorded in our gas segment, which is also the reporting unit for goodwill testing purposes. Accounting guidance requires us to test goodwill for impairment on an annual basis or whenever events or circumstances indicate possible impairment. Absent an indication of fair value from a potential buyer or a similar specific transaction, a combination of the market and income approaches is used to estimate the fair value of goodwill.

We use the market approach which estimates fair value of the gas reporting unit by comparing certain financial metrics to comparable companies. Comparable companies whose securities are actively traded in the public market are judgmentally selected by management based on operational and economic similarities. We utilize EBITDA (earnings before interest, taxes, depreciation, and amortization) multiples of the comparable companies in relation to the EBITDA results of the gas reporting unit to determine an estimate of fair value.

We also utilize a valuation technique under the income approach which estimates the discounted future cash flows of operations. Our procedures include developing a baseline test and performing sensitivity analysis to calculate a reasonable valuation range. The sensitivities are derived from altering those assumptions which are subjective in nature and inherent to a discounted cash flows calculation. Other qualitative factors and comparisons to industry peers are also used to further support the assumptions and ultimately the overall evaluation. A key qualitative assumption considered in our evaluation is the impact of regulation, including rate regulation and cost recovery for the gas reporting unit. Some of the key quantitative assumptions included in our tests involve: regulatory rate design and results; the discount rate; the growth rate; capital spending rates and terminal value calculations. If negative changes occurred to one or more key assumptions, an impairment charge could result. With the exception of the capital spending rate, the key assumptions noted are significantly determined by market factors and significant changes in market factors that impact the gas reporting unit would somewhat be mitigated by our current and future regulatory rate design. Other risks and uncertainties affecting these assumptions include: changes in business, industry, laws, technology and economic conditions. Actual results for the gas reporting unit indicate a slight decline in gas customer count and demand. A continued decline in customer count or demand coupled with an increase in the discount rate would have adverse impacts on the valuation and could result in an impairment charge in the future. Our forecasts anticipate relatively flat customer counts over the next several years.

We weight the results of the two approaches discussed above in order to estimate the fair value of the gas reporting unit. Our annual test performed as of October 2014 indicated the estimated fair market value of the gas reporting unit to be $10 - $14 million higher than its carrying value at that time. While we believe the assumptions utilized in our analysis were reasonable, adverse developments in future periods could negatively impact goodwill impairment considerations, which could adversely impact earnings. Specifically, the quantitative assumptions noted previously, such as an increase to the discount rate or decline in the terminal value calculation could lead to an impairment charge in the future.

Fuel and Purchased Power

Electric Segment

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

In our Missouri jurisdiction, the MPSC establishes a base cost for the recovery of fuel and purchased power expenses used to supply energy for our fuel adjustment clause (FAC). The FAC permits the distribution to customers of 95% of the changes in fuel and purchased power costs prudently incurred above or below the base cost. Off-system sales margins are also part of the recovery of fuel and purchased power costs. As a result, nearly the entire off-system sales margin flows back to the customer. Rates related to the fuel adjustment clause are modified twice a year subject to the review and approval by the MPSC. In accordance with the ASC guidance for regulated operations, 95% of the difference between the actual costs of fuel and purchased power and the base cost of fuel and purchased power recovered from our customers is recorded as an adjustment to fuel and purchased power expense with a corresponding regulatory asset or regulatory liability. If the actual fuel and purchased power costs are higher or lower than the base fuel and purchased power costs billed to customers, 95% of these amounts will be recovered from or refunded to our customers when the fuel adjustment clause is modified.

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

Similar fuel recovery mechanisms are in place for our Oklahoma, Arkansas and FERC jurisdictions.

At December 31, 2014 and 2013, our Missouri, Kansas and Oklahoma fuel and purchased power costs were in a net under-recovered position by $3.1 million and a net over-recovered position of $0.6 million, respectively, which are reflected in our regulatory assets and liabilities.

We receive the renewable attributes associated with the power purchased through our purchased power agreements with Elk River Windfarm LLC and Cloud County Windfarm, LLC. These renewable attributes are converted into renewable energy credits (REC), which are considered inventory, and recorded at zero cost (See Note 11). Revenue from the sale of RECs reduces fuel and purchased power expense.

We have a Stipulation and Agreement with the MPSC granting us authority to manage our SO_2 allowance inventory in accordance with our SO_2 Allowance Management Policy (SAMP). The SAMP allows us to exchange banked allowances for future vintage allowances and/or monetary value and, in extreme market conditions, to sell SO_2 allowances outright for monetary value. We have not yet exchanged or sold any allowances. We classify our allowances as inventory and they are recorded at cost, with allocated allowances being recorded at zero cost. The allowances are removed from inventory on a FIFO basis, and used allowances are considered to be a part of fuel expense (See Note 11). We had 872 and 1,834 SO_2 allowances in inventory at December 31, 2014 and 2013, respectively.

Gas Segment

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

We calculate the PGA factor based on our best estimate of our annual gas costs and volumes purchased for resale. The calculated factor is reviewed by the MPSC staff and approved by the MPSC. Elements considered part of the PGA factor include cost of gas supply, storage costs, hedging contracts, revenue and refunds, prior period adjustments and transportation costs.

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

Derivatives

We utilize derivatives to help manage our natural gas commodity market risk resulting from purchasing natural gas, to be used as fuel in our electric business or sold in our natural gas business, on the spot market and to manage certain interest rate exposure. We also acquire Transmission Congestion Rights (TCR) in an attempt to mitigate congestion costs associated with the power we purchase from the SPP Integrated Marketplace (see Note 14).

Electric Segment

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

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

Gas Segment

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

Cash flows from hedges for both electric and gas segments are classified within cash flows from operations.

Pension and Other Postretirement Benefits

We recognize expense related to pension and other postretirement benefits (OPEB) as earned during the employee's period of service. Related assets and liabilities are established based upon the funded status of the plan compared to the projected benefit obligation. Our pension and OPEB expense or benefit includes amortization of previously unrecognized net gains or losses. Additional income or expense may be recognized when our unrecognized gains or losses as of the most recent measurement date exceed 10% of our postretirement benefit obligation or fair value of plan assets, whichever is greater. For pension benefits and OPEB benefits, unrecognized net gains or losses as of the measurement date are amortized into actuarial expense over ten years.

Pensions

We have rate orders with Missouri, Kansas and Oklahoma that allow us to recover pension costs consistent with our GAAP policy noted above. In accordance with the rate orders, we prospectively calculate the value of plan assets using a market-related value method as allowed by the ASC guidance on pension benefits. As a result, we are allowed to record the Missouri, Kansas and Oklahoma portion of any costs above or below the amount included in rates as a regulatory asset or liability, respectively. The MPSC has allowed us to adopt this pension cost recovery methodology for EDG as well.

Other Postretirement Benefits (OPEB)

We have regulatory treatment for our OPEB costs similar to the treatment described above for pension costs. This includes the use of a market-related value of assets, the amortization of unrecognized gains or losses into actuarial expense over ten years and the recognition of regulatory assets and liabilities as described above.

Additional guidance in the ASC on employers' accounting for defined benefit pension and other postretirement plans requires an employer to recognize the over funded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income of a business entity. The guidance also requires an employer to measure the funded status of a plan as of the date of its year-end statement of financial position, with limited exceptions. Pension and other postretirement employee benefits tracking mechanisms are utilized to allow for future rate recovery of these obligations. We record these as regulatory assets on the balance sheet rather than as reductions of equity through comprehensive income (See Note 7).

Unamortized Debt Discount, Premium and Expense

Discount, premium and expense associated with long-term debt are amortized over the lives of the related issues. Costs, including gains and losses, related to refunded long-term debt are amortized over the lives of the related new debt issues, in accordance with regulatory rate practices.

Liability Insurance

We are primarily self-insured for workers' compensation claims, general liabilities, benefits paid under employee healthcare programs and long-term disability benefits. Accruals are primarily based on the estimated undiscounted cost of claims. We self-insure up to certain limits that vary by segment and type of risk. Periodically, we evaluate the level of insurance coverage over the self-insured limits and adjust insurance levels based on risk tolerance and premium expense. We carry excess liability insurance for workers' compensation and public liability claims for our electric segment. In order to provide for the cost of losses not covered by insurance, an allowance for injuries and damages is maintained based on our loss experience. Our gas segment is covered by excess liability insurance for public liability claims, and workers' compensation claims are covered by a guaranteed cost policy (See Note 11).

Other Noncurrent Liabilities

Other noncurrent liabilities are comprised of accruals and other accounting estimates not sufficiently large enough to merit individual disclosure. At December 31, 2014, the balance of other noncurrent liabilities is primarily comprised of accruals for self-insurance, customer advances for construction and asset retirement obligations.

Cash & Cash Equivalents

Cash and cash equivalents include cash on hand and temporary investments purchased with an initial maturity of three months or less. It also includes checks and electronic funds transfers that have been issued but have not cleared the bank, which are also reflected in current accrued liabilities and were $28.3 million and $22.1 million at December 31, 2014 and 2013, respectively.

Restricted Cash

As part of our Plum Point ownership agreement, we are required to have funds available in an escrow account which guarantees payment of certain operating and construction costs. The cash is held at a financial institution and restricted as to withdrawal or use. The restrictions on these funds related to construction costs, which were approximately $2.5 million at December 31, 2012, were released by all parties in January 2013. The amounts restricted for operating costs, which were $1.8 million at December 31, 2014 and 2013, may increase or decrease based on an annual review.

We are required to post cash collateral with Southwest Power Pool (SPP) to participate in Transmission Congestion Rights (TCR) auctions. The cash is held at a financial institution and restricted as to withdrawal or use. The amounts of such restricted cash were $2.5 million and $1.1 million at December 31, 2014 and 2013, respectively.

Due to our Plum Point energy station interconnection with Midcontinent Independent System Operator (MISO), we participate in Financial Transmission Rights (FTR) auctions which require us to post cash collateral. The cash is held at a financial institution and restricted as to withdrawal or use. The amounts of such restricted cash were $0.5 million and $0 at December 31, 2014 and 2013, respectively.

Fuel, Materials and Supplies

Fuel, materials and supplies consist primarily of coal, natural gas in storage and materials and supplies, which are reported at average cost. These balances are as follows (in thousands):

	2014	2013
Electric fuel inventory	$ 26,454	$ 17,003
Natural gas inventory	5,040	3,584
Materials and supplies	26,305	28,224
TOTAL	$ 57,799	$ 48,811

Income Taxes

Deferred tax assets and liabilities are recognized for the tax consequences of transactions that have been treated differently for financial reporting and tax return purposes; measured using statutory tax rates (See Note 9).

Investment tax credits utilized in prior years were deferred and are being amortized over the useful lives of the properties to which they relate. The longest remaining amortization period for investment tax credits is approximately 50 years.

Accounting for Uncertainty in Income Taxes

In 2006, the FASB issued guidance which clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with the ASC guidance on accounting for income taxes. We file consolidated income tax returns in the U.S. federal and state jurisdictions. With few exceptions, we are no longer subject to U.S. federal, state and local income tax examinations by tax authorities for years before 2009. At December 31, 2014 and 2013, our balance sheet did not include any unrecognized tax benefits. We do not expect any material changes to unrecognized tax benefits within the next twelve months. We recognize interest and penalties, if any, related to unrecognized tax benefits in other expenses.

Computations of Earnings per Share

The ASC guidance on earnings per share requires dual presentation of basic and diluted earnings per share. Basic earnings per share does not include potentially dilutive securities and is computed by dividing net income by the weighted average number of common shares outstanding. Diluted earnings per share assumes the issuance of common shares pursuant to the Company's stock-based compensation plans at the beginning of each respective period, or at the date of grant or award if later. Shares attributable to stock options are excluded from the calculation of diluted earnings per share if the effect would be antidilutive.

Weighted Average Number Of Shares	2014	2013	2012
Basic	43,291,031	42,781,382	42,256,641
Dilutive Securities:			
Performance-based restricted stock awards	8,809	12,142	14,500
Dividend equivalents	-	-	6,329
Employee stock purchase plan	3,422	1,729	1,996
Stock options	-	61	3,160
Time-based restricted stock awards	10,666	7,907	1,820
Total dilutive securities	22,897	21,839	27,805
Diluted weighted average number of shares	43,313,928	42,803,221	42,284,446
Antidilutive Shares	25,259	107,100	128,500

Potentially dilutive shares are not expected to have a material impact unless significant appreciation of the Company's stock price occurs.

Stock-Based Compensation

We have several stock-based compensation plans, which are described in more detail in Note 8. In accordance with the ASC guidance on stock-based compensation, we recognize compensation expense over the requisite service period of all stock-based compensation awards based upon the fair-value of the award as of the date of issuance.

Recently Issued and Proposed Accounting Standards

Presentation of an unrecognized tax benefit: In July 2013, The FASB issued new guidance on the presentation of unrecognized tax benefits. Under this guidance, an unrecognized tax benefit would be presented as a reduction to a deferred tax asset when a tax credit carryforward, net operating loss carryforward, or similar tax loss exists. To the extent that the loss or credit carryforward is not available at the reporting date or the entity does not intend to use the deferred tax asset for such a purpose, the unrecognized tax benefit should be presented as a liability and not be combined with deferred tax assets. This standard is effective for annual periods beginning after December 15, 2013. The application of this standard did not have a material impact on our results of operations, financial position or liquidity.

Revenue from contracts with customers: In June 2014, the FASB issued new guidance governing revenue recognition. Under the new guidance, an entity is required to recognize revenue in a pattern that depicts the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The new standard is effective for interim and annual reporting periods beginning after December 15, 2016. We are evaluating the impact of the adoption of this standard.

2. PROPERTY, PLANT AND EQUIPMENT

Our total property, plant and equipment are summarized below (in thousands).

	December 31, 2014	December 31, 2013
Electric plant		
Production	$ 1,159,140	$ 1,035,095
Transmission	288,542	263,398
Distribution	840,761	793,024
General(1)	119,572	115,427
Electric plant	2,408,015	2,206,944
Less accumulated depreciation and amortization	704,596	697,128
Electric plant net of depreciation and amortization	1,703,419	1,509,816
Construction work in progress	110,500	150,636
Net electric plant	**1,813,919**	**1,660,452**
Water plant	12,809	12,661
Less accumulated depreciation and amortization	5,102	4,806
Water plant net of depreciation and amortization	7,707	7,855
Construction work in progress	146	-
Net water plant	**7,853**	**7,855**
Net electric segment plant	**1,821,772**	**1,668,307**
Gas plant		
Transmission	11,198	10,550
Distribution	89,712	84,157
General (2)	(21,546)	(21,873)
Gas Plant	79,364	72,834
Less accumulated depreciation and amortization	16,405	15,204
Gas plant net of accumulated depreciation	62,959	57,630
Construction work in progress	379	1,156
Net gas plant	**63,338**	**58,786**

	December 31,	
	2014	2013
Other		
Fiber	41,394	39,902
Less accumulated depreciation and amortization	17,304	15,599
Non-regulated net of depreciation and amortization	24,090	24,303
Construction work in progress	1,072	538
Net non-regulated property	**25,162**	**24,841**
TOTAL NET PLANT AND PROPERTY	**$ 1,910,272**	**$ 1,751,934**

(1) Includes intangible property of $41.2 and $38.1 million as of December 31, 2014 and 2013, respectively, primarily related to capitalized software and investments in facility upgrades owned by other utilities. Accumulated amortization related to this property in 2014 and 2013 was $15.7 and $13.1 million, respectively.

(2) Includes intangible property of $0.7 and $0.7 million as of December 31, 2014 and 2013, respectively, primarily related to capitalized software and investments in facility upgrades owned by other utilities. Accumulated amortization related to this property in 2014 and 2013 was $0.5 million and $0.5 million, respectively.

The table below summarizes the total provision for depreciation and the depreciation rates for continuing operations, both capitalized and expensed, for the years ended December 31 (in thousands):

	2014	2013	2012
Provision for depreciation			
Regulated – Electric and Water	$ 66,600	$ 63,192	$ 57,467
Regulated – Gas	3,851	3,763	3,602
Non-Regulated	1,891	1,938	1,538
TOTAL	**72,342**	**68,893**	**62,607**
Amortization	2,692	2,492	1,041
TOTAL	**$ 75,034**	**$ 71,385**	**$ 63,648**

	2014	2013	2012
Annual depreciation rates			
Electric and water	3.0%	3.0%	2.8%
Gas	5.2%	5.4%	5.4%
Non-Regulated	4.7%	5.0%	4.2%
TOTAL COMPANY	**3.0%**	**3.1%**	**2.9%**

The table below sets forth the average depreciation rate for each class of assets for each period presented:

Annual Weighted Average Depreciation Rate	2014	2013	2012
Electric fixed assets:			
Production plant	2.4%	2.4%	2.0%
Transmission plant	2.4%	2.4%	2.4%
Distribution plant	3.6%	3.6%	3.6%
General plant	5.8%	5.8%	5.9%
Water	2.7%	2.8%	2.7%
Gas	5.2%	5.4%	5.4%
Non-regulated	4.7%	5.0%	4.2%

3. REGULATORY MATTERS

Regulatory Assets and Liabilities and Other Deferred Credits

Changes

There were no changes to regulatory assets and liabilities with regards to their rate base inclusion or amortizable lives from December 31, 2013 to December 31, 2014. Changes to regulatory assets and liabilities regarding their rate base inclusion or amortizable lives from December 31, 2012 to December 31, 2013 resulted from our 2012 Missouri rate case. As a result of this case, deferred costs from the tornado that hit our service territory on May 22, 2011 will be recovered over the next ten years. In addition, the order also included the continuation of tracking mechanisms for expenses related to employee pension, retiree health care, vegetation management, and Iatan 2, Iatan Common and Plum Point operating and maintenance costs as well as the capitalization of banking and line of credit fees.

The following table sets forth the components of our regulatory assets and regulatory liabilities on our consolidated balance sheet (in thousands).

	December 31, 2014	December 31, 2013
Regulatory Assets:		
Current:		
Under recovered fuel costs	$ 2,618	$ 1,411
Current portion of long-term regulatory assets	8,134	6,332
Regulatory assets, current	10,752	7,743
Long-term:		
Pension and other postretirement benefits[1]	111,121	70,035
Income taxes	47,177	48,033
Deferred construction accounting costs[2]	15,521	16,275
Unamortized loss on reacquired debt	10,405	11,078
Unsettled derivative losses – electric segment	9,037	4,269
System reliability – vegetation management	5,337	7,539
Storm costs[3]	4,183	4,911
Asset retirement obligation	5,145	4,673
Customer programs	5,253	4,935
Unamortized loss on interest rate derivative	943	989
Deferred operating and maintenance expense	910	2,095
Under recovered fuel costs	640	-
Current portion of long-term regulatory assets	(8,134)	(6,332)
Other	2,179	833
Regulatory assets, long-term	209,717	169,333
Total Regulatory Assets	$ 220,469	$ 177,076
Regulatory Liabilities		
Current:		
Over recovered fuel costs	$ 4,227	$ 2,212
Current portion of long-term regulatory liabilities	3,671	3,469
Regulatory liabilities, current	7,898	5,681
Long-term:		
Costs of removal	90,527	88,469
SWPA payment for Ozark Beach lost generation	16,744	19,405
Income taxes	11,451	11,677
Deferred construction accounting costs – fuel[4]	7,849	8,011
Unamortized gain on interest rate derivative	3,201	3,371
Pension and other postretirement benefits	2,369	2,177
Over recovered fuel costs	1	2,371
Current portion of long-term regulatory liabilities	(3,671)	(3,469)
Regulatory liabilities, long-term	128,471	132,012
Total Regulatory Liabilities	$ 136,369	$ 137,693

(1) Primarily consists of unfunded pension and OPEB liability. See Note 7.

(2) Reflects deferrals resulting from 2005 regulatory plan relating to Iatan 1, Iatan 2 and Plum Point. These amounts are being recovered over the life of the plants.

(3) Reflects ice storm costs incurred in 2007 and costs incurred as a result of the May 2011 tornado including an accrued carrying charge and deferred depreciation totaling $3.3 million at December 31, 2014.

(4) Resulting from regulatory plan requiring deferral of the fuel and purchased power impacts of Iatan 2.

Unamortized losses on debt and losses on interest rate derivatives are not included in rate base, but are included in our capital structure for rate base purposes. The remainder of our regulatory assets are not included in rate base, generally because they are not cash items. However, as of December 31, 2014, the costs of all of our regulatory assets are currently being recovered except for approximately $103.5 million of pension and other postretirement costs primarily related to the unfunded liabilities for future pension and OPEB costs. The amount and timing of recovery of this item will be based on the changing funded status of the pension and OPEB plans in future periods.

The regulatory income tax assets and liabilities are generally amortized over the average depreciable life of the related assets. The loss on reacquired debt and the loss and gain on interest rate derivatives are amortized over the life of the related new debt issue, which currently ranges from 6 to 26 years. The unrecovered fuel costs are generally recovered within a year following their recognition. Severe storm costs and the Asbury maintenance outage costs are recovered over five years. Pension and other postretirement benefit tracking mechanisms are recovered over a five year period. The cost of removal regulatory liability is amortized as removal costs are incurred.

RATE MATTERS

We routinely assess the need for rate relief in all of the jurisdictions we serve and file for such relief when necessary.

Our rates for retail electric and natural gas services (other than specially negotiated retail rates for industrial or large commercial customers, which are subject to regulatory review and approval) are determined on a "cost of service" basis. Rates are designed to provide, after recovery of allowable operating expenses, an opportunity to earn a reasonable return on "rate base." "Rate base" is generally determined by reference to the original cost (net of accumulated depreciation and amortization) of utility plant in service, subject to various adjustments for deferred taxes and other items. Over time, rate base is increased by additions to utility plant in service and reduced by depreciation, amortization and retirement of utility plant or write-off's as ordered by the utility commissions. In general, a request of new rates is made on the basis of a "rate base" as of a date prior to the date of the request and allowable operating expenses for a 12-month test period ended prior to the date of the request. Although the current rate making process provides recovery of some future changes in rate base and operating costs, it does not reflect all changes in costs for the period in which new retail rates will be in place. This results in a lag (commonly referred to as "regulatory lag") between the time we incur costs and the time when we can start recovering the costs through rates.

The following table sets forth information regarding electric and water rate increases since January 1, 2012:

Jurisdiction	Date Requested	Annual Increase Granted	Percent Increase Granted	Date Effective
Arkansas - Electric	December 3, 2013	$ 1,366,809	11.34%	September 26, 2014
Missouri – Electric	July 6, 2012	$ 27,500,000	6.78%	April 1, 2013
Missouri – Water	May 21, 2012	$ 450,000	25.5%	November 23, 2012
Kansas – Electric	June 17, 2011	$ 1,250,000	5.20%	January 1, 2012
Oklahoma – Electric	June 30, 2011	$ 240,722	1.66%	January 4, 2012

Electric Segment

Missouri

2014 Rate Case

On August 29, 2014, we filed a request with the MPSC for changes in rates for our Missouri electric customers. We requested an annual increase in total revenue of approximately $24.3 million, or approximately 5.5%. The main cost drivers in the rate increase are the costs associated with our investment in Air Quality Control Facilities at our Asbury power plant (See Note 11 – New Construction) that were incurred to comply with the Environmental Protection Agency's (EPA) rules governing the continued operation of the plant, increases in property taxes, increases in ongoing maintenance expenses and increases in Regional Transmission Organization transmission fees.

2012 Rate Cases

On February 22, 2013, we filed a Nonunanimous Stipulation and Agreement (Agreement) with the MPSC which issued an order approving the Agreement on February 27, 2013. The Agreement provided for an annual increase in base revenues for our Missouri electric customers in the amount of approximately $27.5 million, effective April 1, 2013, and the continuation of the current fuel adjustment mechanism. In 2011 the MPSC permitted us to defer actual incremental operating and maintenance expenses associated with the repair, restoration and rebuilding activities resulting from the May 2011 tornado. In addition, depreciation related to the capital expenditures was allowed to be deferred and a carrying charge accrued. Approximately $4.0 million was deferred in total for the tornado costs. Recovery of these costs over the ten years was included in the Agreement

The Agreement also included an increase in depreciation rates, and the continuation of tracking mechanisms for expenses related to employee pension, retiree health care, vegetation management, and Iatan 2, Iatan Common and Plum Point operating and maintenance costs. In addition, the Agreement included a write-off of approximately $3.6 million, consisting of a $2.4 million disallowance for the prudency of certain construction expenditures for Iatan 2 and a $1.2 million regulatory reversal of a prior period gain on sale of our Asbury unit train, which is included in regulated operating expenses. We also agreed not to implement a Missouri general rate increase prior to October 1, 2014. As initially filed on July 6, 2012, we requested an annual increase in base rates for our Missouri electric customers in the amount of $30.7 million, or 7.56%, and the continuation of the fuel adjustment clause.

On May 21, 2012, we filed a rate increase request with the MPSC for an annual increase in revenues for our Missouri water customers in the amount of approximately $516,400, or 29.6%. On October 18, 2012, we, the MPSC staff and the Office of the Public Counsel filed a unanimous agreement with the MPSC for an increase of $450,000. The MPSC issued an order approving the agreement on October 31, 2012, with rates effective November 23, 2012.

Kansas

2014 Environmental Cost Recovery Rider

On December 5, 2014, we filed for approval of an environmental cost recovery rider designed to recover the costs associated with our investment in Air Quality Control Facilities at our Asbury generating unit. As proposed, the rider would recover $859,674 during the first twelve months of the tariffs operation.

2011 Rate Case

On November 10, 2011 a joint settlement agreement was filed, and approved by the KCC on December 21, 2011, resulting in an increase in annual revenues of $1.25 million, or approximately 5.2%. The new rates became effective on January 1, 2012. On June 17, 2011, we filed an application with the KCC seeking a rate increase of $1.5 million, or 6.39%. The rate increase was requested to recover the costs associated with our investment in the Iatan 1, Iatan 2 and Plum Point generating units and the depreciation and operation and maintenance costs deferred since the in-service dates of the units. The June 17, 2011 filing was made under the KCC's abbreviated rate case rules which the KCC authorized in our 2009 Kansas rate case. The case included a request to recover the Iatan and Plum Point cost deferrals over a 3-year period.

Oklahoma

On June 30, 2011, we filed a request with the Oklahoma Corporation Commission (OCC) for an annual increase in base rates for our Oklahoma electric customers in the amount of $0.6 million, or 4.1% over the base rate and Capital Reliability Rider (CRR) revenues that were currently in effect. A stipulation and agreement, reached by all parties participating in the case, was filed on November 16, 2011. This agreement, which was approved by the OCC on January 4, 2012, made rates previously collected under the CRR permanent, and will result in a net overall increase of total annual revenues of $0.2 million, or approximately 1.66%. The agreement also removed fuel and purchase power costs from base rates. Fuel and purchase power costs are now listed as a separate line item, identified as the Fuel Adjustment Charge, on customer bills.

Arkansas

On May 20, 2014, we filed a settlement agreement with the Arkansas Public Service Commission (APSC) for an increase of $1.375 million, or approximately 11%. A hearing was held on the settlement agreement on July 22, 2014. On September 16, 2014, the APSC issued an order approving the settlement with a modification that reduced the overall revenue increase to $1.367 million. The new rates were effective September 26, 2014. We had filed a request on December 3, 2013, with the APSC seeking an annual increase in total revenue of approximately $2.2 million, or approximately 18%. The rate increase was requested to recover costs incurred to ensure continued reliable service for our customers, including capital investments, operating systems replacement costs and ongoing increases in other operation and maintenance expenses and capital costs.

FERC

We have in place a cost-based transmission formula rate (TFR). On June 13, 2013, we, the Kansas Corporation Commission and the cities of Monett, Mt. Vernon and Lockwood, Missouri and Chetopa, Kansas, filed a unanimous Settlement Agreement (Agreement) with the FERC. The Agreement included a TFR that would establish an ROE of 10.0%. The Agreement calls for the TFR to be updated annually with the new updated TFR rates effective on July 1 of each year. FERC conditionally approved the Agreement on November 18, 2013, and we made a compliance filing with FERC on December 18, 2013 in connection with this conditional approval. The FERC approved our compliance filing on June 12, 2014.

We have in place a cost-based generation formula rate (GFR). Our GFR requires an update to be completed annually for rates effective June 1. On October 29, 2014, Empire made a “limited” Section 205 filing to request some minor changes in the existing GFR formula to incorporate the impact of the recent implementation of the Southwest Power Pool Integrated Marketplace (IM). As a result of this filing, our customers’ share of the margins we receive from sales into the IM will be passed on to them through the monthly fuel and purchased power cost adjustment mechanism rather than making one-time adjustments at each annual update. This filing was approved by FERC on January 13, 2015.

MARKETS AND TRANSMISSION

Electric Segment

Day Ahead Market: On March 1, 2014, the SPP RTO implemented its Integrated Marketplace (or Day-Ahead Market), which replaced the Energy Imbalance Services (EIS) market. The SPP RTO created a single NERC-approved balancing authority (BA) that took over balancing authority responsibilities for its members, including Empire.

As part of the Integrated Marketplace (IM), we and other SPP members submit generation offers to sell our power and bids to purchase power into the SPP market, with the SPP serving as a centralized dispatch of SPP members’ generation resources. The SPP matches offers and bids based upon operating and reliability considerations. It is expected that 90%-95% of all next day generation needed throughout the SPP territory will be cleared through this IM. We also acquire Transmission Congestion Rights (TCR) in an attempt to mitigate congestion costs associated with the power we will purchase from the IM. The activity for each market participant is settled in various time increments. When we sell more generation to the market than we purchase, based on the prescribed time increments, the net sale is included as part of electric revenues. When we purchase more generation from the market than we sell, based on the prescribed time increments, the net purchase is recorded as a component of fuel and purchased power on our financial statements. The net financial effect of these Integrated Marketplace transactions is included in our fuel adjustment mechanisms.

FERC Order No. 1000: In July 2011, the FERC issued Order No. 1000 (Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities) which requires all public utility transmission providers to allow transmission developers outside their retail distribution service territory to participate in regional transmission planning. Order No. 1000 eliminates the federal right of first refusal for entities that develop transmission projects within their own retail distribution service territories to construct transmission facilities selected in a regional transmission plan. This order will directly affect our rights to build 161kV and above transmission facilities within our retail service territory.

Order No. 1000 also directed transmission providers to develop policy and procedures for regional and interregional transmission planning as well as regional and interregional transmission cost allocation (see "SPP Regional Transmission Development" below) for approved transmission projects. We continue to participate in the SPP processes to understand the impact of these FERC orders on our ability to construct new facilities within our service territory as well as their influence on promoting construction of transmission projects on or near our borders with our neighbors. SPP has completed and filed with the FERC a required interregional policy and procedure compliance filing, with implementation to occur once FERC has approved the filing. FERC's decision on SPP's Order No. 1000 interregional compliance filing is pending.

SPP Regional Transmission Development: In 2010, SPP received FERC approval to implement a new highway/byway cost allocation methodology for new SPP approved transmission projects. We actively monitor SPP's policy to allocate the costs of transmission projects to its members. We estimate our net transmission costs will increase between $3 and $4 million in 2015 over what we currently recover in rates as a result of SPP's allocation methodology. We have cost recovery mechanisms in place in our Arkansas and Oklahoma jurisdictions that allow us to recover the additional SPP transmission costs outside the traditional rate case process. Currently no mechanism is in place to timely recover additional costs resulting from the portion of these transmission projects allocated to us other than through the traditional rate case process in our Missouri and Kansas jurisdictions. Within our current rate case proceeding in Missouri, we have requested a transmission recovery mechanism to be implemented effective August 2015.

The highway/byway allocation methodology requires the costs of SPP approved transmission projects to be allocated to 1) members across the entire SPP region; 2) members within certain localized service territories or zones; or 3) a combination of both regional and zonal allocation. The allocation is based on project voltage, as follows:

Transmission Project Voltage	Regional Funding Percentage	Zonal Funding Percentage
300 kV and Above	100.0%	0.0%
100kV to 299kV	33.3%	66.7%
Below 100 kV	0.0%	100.0%

SPP's formal regional cost allocation review and benefit to cost imbalance analysis process is ongoing and being formalized within SPP's Open Access Transmission Tariff in 2015. This process will evaluate the long term projected benefits against the allocated costs of transmission projects to determine if remedies (cost reductions or benefit increases due to specific transmission projects) are needed for our customers. SPP will evaluate potential equity improvement remedies in its Integrated Transmission Planning (ITP), Inter-regional Transmission Planning (Order 1000) and regional cost allocation review (RCAR) processes with recommendations expected in July 2015.

SPP/Midcontinent Independent System Operator (MISO) Joint Operating Agreement and Plum Point Delivery: On December 19, 2013, Entergy voluntarily integrated its generation, transmission, and load into the MISO regional transmission organization. Based on the current terms and conditions of MISO membership, Entergy's participation in MISO will not be beneficial to our customers as it will increase transmission delivery costs for our Plum Point power station as well as utilize our transmission system without compensation.

As a result, SPP and its members have undertaken certain actions with FERC to address these issues and reduce the costs to our customers. FERC has set settlement evidentiary hearings for these issues. The dispute is likely to move into litigation hearings before the FERC if the settlement process is unsuccessful.

Gas Segment

Non-residential gas customers whose annual usage exceeds certain amounts may purchase natural gas from a source other than EDG. EDG does not have a non-regulated energy marketing service that sells natural gas in competition with outside sources. EDG continues to receive non-gas related revenues for distribution and other services if natural gas is purchased from another source by our eligible customers.

Other - Rate Matters

In accordance with ASC guidance on regulated operations, we currently have deferred approximately $0.5 million of expense related to rate cases under other non-current assets and deferred charges. These amounts will be amortized over varying periods based upon the completion of the specific cases. Based on past history, we expect all these expenses to be recovered in rates.

4. SHAREHOLDERS' EQUITY

Shelf Registration

We have a $200.0 million shelf registration statement with the SEC, effective December 13, 2013, covering our common stock, unsecured debt securities, preference stock, and first mortgage bonds. As of December 31, 2014, $200.0 million remains available for issuance under this shelf registration statement. However, as a result of our regulatory approvals, of the original $200.0 million, $150.0 million was available for first mortgage bonds with $90.0 million remaining available after the issuance of $60 million in first mortgage bonds on December 1, 2014. We plan to use proceeds from offerings made pursuant to this shelf to fund capital expenditures, refinance existing debt or general corporate needs during the three-year effective period.

Employee Benefit Plans

Our Employee Stock Purchase Plan permits the grant to eligible employees of options to purchase our common stock at a discounted price. As of December 31, 2014 and 2013, there were 820,838 and 127,774 shares available for issuance in this plan, respectively. Under our Employee 401(k) Plan and ESOP we match a percentage of each employee's deferrals by contributing shares of our common stock. At December 31, 2014 and 2013 there were 196,399 and 256,448 shares available to be issued respectively. (See Note 7 for further discussion of these plans).

Equity Based Compensation

We have several stock-based awards programs, which are described in Note 8. Our 2015 Stock Incentive Plan provides for grants of up to 500,000 shares of common stock through January 2025.

Dividends

Holders of our common stock are entitled to dividends if, as and when declared by the Board of Directors, out of funds legally available therefore, subject to the prior rights of holders of any outstanding cumulative preferred stock and preference stock. Payment of dividends is determined by our Board of Directors after considering all relevant factors, including the amount of our retained earnings (which is essentially our accumulated net income less dividend payouts). A reduction of our dividend per share, partially or in whole, could have an adverse effect on our common stock price.

The following table shows our diluted earnings per share, dividends paid per share, total dividends paid and retained earnings balance for the years ended December 31, 2014, 2013 and 2012:

(in millions, except per share amounts)	2014	2013	2012
Diluted earnings per share	$ 1.55	$ 1.48	$ 1.32
Dividends paid per share	$ 1.025	$ 1.005	$ 1.00
Total dividends paid	$ 44.4	$ 43.0	$ 42.3
Retained earnings year-end balance	$ 90.3	$ 67.6	$ 47.1

Under Kansas corporate law, our Board of Directors may only declare and pay dividends out of our surplus or, if there is no surplus, out of our net profits for the fiscal year in which the dividend is declared or the preceding fiscal year, or both. Our surplus, under Kansas law, is equal to our retained earnings plus accumulated other comprehensive income/(loss), net of income tax. However, Kansas law does permit, under certain circumstances, our Board of Directors to transfer amounts from capital in excess of par value to surplus. In addition, Section 305(a) of the Federal Power Act (FPA) prohibits the payment by a utility of dividends from any funds "properly included in capital account". There are no additional rules or regulations issued by the FERC under the FPA clarifying the meaning of this limitation. However, several decisions by the FERC on specific dividend proposals suggest that any determination would be based on a fact-intensive analysis of the specific facts and circumstances surrounding the utility and the dividend in question, with particular focus on the impact of the proposed dividend on the liquidity and financial condition of the utility.

In addition, the EDE Mortgage and our Restated Articles contain certain dividend restrictions. The most restrictive of these is contained in the EDE Mortgage, which provides that we may not declare or pay any dividends (other than dividends payable in shares of our common stock) or make any other distribution on, or purchase (other than with the proceeds of additional common stock financing) any shares of, our common stock if the cumulative aggregate amount thereof after August 31, 1944 (exclusive of the first quarterly dividend of $98,000 paid after said date) would exceed the sum of $10.75 million and the earned surplus (as defined in the EDE Mortgage) accumulated subsequent to August 31, 1944, or the date of succession in the event that another corporation succeeds to our rights and liabilities by a merger or consolidation. The EDE Mortgage permits the payment of any dividend or distribution on, or purchase of, shares of our common stock within 60 days after the related date of declaration or notice of such dividend, distribution or purchase if (i) on the date of declaration or notice, such dividend, distribution or purchase would have complied with the provisions of the EDE Mortgage and (ii) as of the last day of the calendar month ended immediately preceding the date of such payment, our ratio of total indebtedness to total capitalization (after giving pro forma effect to the payment of such dividend, distribution, or purchase) was not more than 0.625 to 1.

Preferred and Preference Stock

We have 2.5 million shares of preference stock authorized, including 0.5 million shares of Series A Participating Preference Stock, none of which have been issued. We have 5 million shares of $10.00 par value cumulative preferred stock authorized. There was no preferred stock issued and outstanding at December 31, 2014 or 2013.

5. LONG-TERM DEBT

At December 31, 2014 and 2013, the balance of long-term debt outstanding was as follows (in thousands):

	2014	2013
First mortgage bonds (EDE):		
7.20% Series due 2016	$ 25,000	$ 25,000
6.375% Series due 2018 [1]	90,000	90,000
4.65% Series due 2020 [1]	100,000	100,000
3.58% Series due 2027 [1]	88,000	88,000
3.73% Series due 2033 [1]	30,000	30,000
5.875% Series due 2037 [1]	80,000	80,000
5.20% Series due 2040 [1]	50,000	50,000
4.32% Series due 2043 [1]	120,000	120,000
4.27% Series due 2044 [1]	60,000	-
First mortgage bonds (EDG):		
6.82% Series due 2036 [1]	55,000	55,000
	698,000	638,000
Senior Notes, 6.70% Series due 2033 [1]	62,000	62,000
Senior Notes, 5.80% Series due 2035 [1]	40,000	40,000
Other	4,167	4,441
Less unamortized net discount	(686)	(739)
	803,481	743,702
Less current obligations under capital lease	(292)	(274)
TOTAL LONG-TERM DEBT	**$ 803,189**	**$ 743,428**

(1) We may redeem some or all of the notes at any time at 100% of their principal amount, plus a make-whole premium, plus accrued and unpaid interest to the redemption date.

Debt Financing Activities

On October 15, 2014, we entered into a Bond Purchase Agreement for a private placement of $60.0 million of 4.27% First Mortgage Bonds due December 1, 2044. A delayed settlement occurred on December 1, 2014. Interest is payable semi-annually on the bonds on each December 1 and June 1, commencing June 1, 2015. The bonds may be redeemed at our option, at any time prior to maturity, at par plus a make whole premium, together with accrued and unpaid interest, if any, to the redemption date. The proceeds from the sale of the bonds were used to refinance existing short-term indebtedness and for general corporate purposes. The bonds have not been, and will not be, registered under the Securities Act of 1933, as amended. The bonds were issued under the EDE Mortgage.

On October 30, 2012, we entered into a Bond Purchase Agreement for a private placement of $30.0 million of 3.73% First Mortgage Bonds due 2033 and $120.0 million of 4.32% First Mortgage Bonds due 2043. The delayed settlement occurred on May 30, 2013. The interest is payable semi-annually on the bonds on each May 30 and November 30, commencing November 30, 2013. The bonds may be redeemed at our option, at any time prior to maturity, at par plus a make whole premium, together with accrued and unpaid interest, if any, to the redemption date. A portion of the proceeds were used to redeem all $98.0 million aggregate principal amount of our Senior Notes, 4.50% Series due June 15, 2013. The remaining proceeds were used for general corporate purposes. The bonds have not been registered under the Securities Act of 1933, as amended. The bonds were issued under the EDE Mortgage.

Shelf Registration

We have a $200 million shelf registration statement with the SEC that is effective for three years from December 13, 2013. See Note 4.

EDE Mortgage Indenture

Substantially all of the property, plant and equipment of The Empire District Electric Company (but not its subsidiaries) are subject to the lien of the EDE Mortgage. Restrictions in the EDE mortgage bond indenture could affect our liquidity. The principal amount of all series of first mortgage bonds outstanding at any one time under the EDE Mortgage is limited by terms of the mortgage to $1 billion. Based on this limit and our current level of outstanding first mortgage bonds, we are limited to the issuance of $357 million of new first mortgage bonds. The EDE Mortgage contains a requirement that for new first mortgage bonds to be issued, our net earnings (as defined in the EDE Mortgage) for any twelve consecutive months within the fifteen months preceding issuance must be two times the annual interest requirements (as defined in the EDE Mortgage) on all first mortgage bonds then outstanding and on the prospective issue of new first mortgage bonds. Our earnings for the year ended December 31, 2014 would permit us to issue approximately $615.9 million of new first mortgage bonds based on this test with an assumed interest rate of 5.5%. In addition to the interest coverage requirement, the EDE Mortgage provides that new bonds must be issued against, among other things, retired bonds or 60% of net property additions. At December 31, 2014, we had retired bonds and net property additions which would enable the issuance of at least $952.5 million principal amount of bonds if the annual interest requirements are met. As of December 31, 2014, we are in compliance with all restrictive covenants of the EDE Mortgage.

EDG Mortgage Indenture

The principal amount of all series of first mortgage bonds outstanding at any one time under the EDG Mortgage is limited by terms of the mortgage to $300 million. Substantially all of the property, plant and equipment of The Empire District Gas Company are subject to the lien of the EDG Mortgage. The EDG Mortgage contains a requirement that for new first mortgage bonds to be issued, the amount of such new first mortgage bonds shall not exceed 75% of the cost of property additions acquired after the date of the Missouri Gas acquisition. The mortgage also contains a limitation on the issuance by EDG of debt (including first mortgage bonds, but excluding short-term debt incurred in the ordinary course under working capital facilities) unless, after giving effect to such issuance, EDG's ratio of EBITDA (defined as net income plus interest, taxes, depreciation, amortization and certain other non-cash charges) to interest charges for the most recent four fiscal quarters is at least 2 to 1. As of December 31, 2014, this test would allow us to issue approximately $19.7 million principal amount of new first mortgage bonds at an assumed interest rate of 5.5%.

Our long-term debt obligations over the next five years are as follows (in thousands):

	Payments Due By Period		
Long-Term Debt Payout Schedule (Excluding Unamortized Discount (in thousands)	**Total**	**Regulated Entity Debt Obligations**	**Capital Lease Obligations**
2015	$ 292	$ -	$ 292
2016	25,308	25,000	308
2017	325	-	325
2018	90,347	90,000	347
2019	371	-	371
Thereafter	687,524	685,000	2,524
Total long-term debt obligations	**804,167**	**$ 800,000**	**$ 4,167**
Less current obligations and unamortized discount	978		
TOTAL LONG-TERM DEBT	**$ 803,189**		

6. SHORT-TERM BORROWINGS

At December 31, 2014, total short-term borrowings consisted of $44.0 million in commercial paper and no borrowings from our line of credit. During 2014 and 2013 our short-term borrowings outstanding averaged (in millions)

	2014	**2013**
Average borrowings outstanding	$30.0	$ 8.7
Highest month end balance	$77.0	$29.0

The weighted average interest rates and the weighted average interest rate of borrowings outstanding at December 31, 2014 and 2013 were:

	2014	2013
Weighted average interest rate	0.38%	0.69%
Weighted average interest rate of borrowings outstanding	0.44%	0.33%

On October 20, 2014, we entered into a new $200 million 5-year Credit Agreement replacing the former $150 million Third Amended and Restated Unsecured Credit Agreement dated January 17, 2012 which had a January 2017 expiration date. This new agreement may be used for working capital, commercial paper back-up and general corporate purposes. The credit facility includes a $20 million swingline loan sublimit, a $20 million sublimit for letters of credit issuance and, subject to bank approval, a $75 million accordion feature and two one-year extensions of the credit facility's maturity date.

Interest on borrowings under the new facility accrues at a rate equal to, at our option, (i) the highest of (A) the agent prime rate, (B) the federal funds effective rate plus 0.5% or (C) one month LIBOR plus 1.0%, in each case, plus a margin or (ii) one month, two month, three month or six month LIBOR, in each case, plus a margin. Each margin is based on our current credit ratings and the pricing schedule in the facility. As of the date hereof, and based on our current credit ratings, the LIBOR margin under the facility is 1.025%. A facility fee is payable quarterly on the full amount of the commitments under the facility based on our current credit ratings, which is currently 0.175%. In addition, upon entering into the new credit facility, we paid upfront fees to the revolving credit banks of $0.3 million in the aggregate.

The new credit facility requires our total indebtedness to be less than 65.0% of our total capitalization at the end of each fiscal quarter and a failure to maintain this ratio will result in an event of default under the credit facility and will prohibit us from borrowing funds thereunder. As of December 31, 2014, we were in compliance with this covenant as our ratio of total indebtedness to total capitalization was 0.52 to 1.0. The new credit facility is also subject to cross-default if we default on more than $25 million in the aggregate on our other indebtedness. As of December 31, 2014, we were not in default under any of our debt obligations.

The new credit agreement does not legally restrict the use of our cash in the normal course of operations. There were no outstanding borrowings under the agreement at December 31, 2014; however, $44.0 million was used to back up our outstanding commercial paper.

7. RETIREMENT AND OTHER EMPLOYEE BENEFITS

We record retirement benefits in accordance with the ASC guidance on accounting for pension and other postretirement benefits, and have recorded the appropriate liabilities to reflect the unfunded status of our benefit plans, with offsetting entries to a regulatory asset, because we believe it is probable the unfunded amount of these plans will be afforded rate recovery. Additionally, the MPSC agreed that the effects of purchase accounting entries related to pension and other post-retirement benefits would be recoverable in future rate proceedings. These amounts, which are related to EDG, were recorded as regulatory assets and are being amortized. The tax effects of these entries are reflected as deferred tax assets and liabilities and regulatory liabilities.

Annually we evaluate the discount rate, retirement age, compensation rate increases, expected return on plan assets, healthcare cost trend rate, and other actuarial assumptions related to pension benefit and post-retirement medical plan. We utilize an interest rate yield curve to determine an appropriate discount rate. The yield curve is constructed based on the yields on over 500 high-quality, non-callable corporate bonds with maturities between zero and thirty years. A theoretical spot rate curve constructed from this yield curve is then used to discount the annual benefit cash flows of the Empire pension plan and develop a single point discount rate matching the plan's payout structure. In evaluating these assumptions, many factors are considered, including, current market conditions, asset allocations, changes in demographics and the views of leading financial advisors and economists. In evaluating the expected retirement age assumption, we consider the retirement ages of past employees eligible for pension and medical benefits together with expectations of future retirement ages. It is reasonably possible that changes in these assumptions will occur in the near term and, due to the uncertainties inherent in setting assumptions, the effect of such changes could be material to the Company's consolidated financial statements. A roll forward technique is used to value the year ending pension obligations. The roll forward technique values the year-end obligation by rolling forward the beginning-of-year obligation using the demographic assumptions disclosed below. The economic assumptions are updated as of the end of the year. All of the benefit plans have been measured as of December 31, 2014, consistent with previous years. See Note 1.

Pensions

Our non-contributory defined benefit pension plan includes all employees meeting minimum age and service requirements. Effective on January 1, 2014, the plan was amended to include a cash balance benefit formula. Employees hired on or after January 1, 2014 will accrue benefits based on a cash balance methodology. Employees hired prior to January 1, 2014 were given a one-time option to convert to the cash balance methodology, or remain with our traditional average annual basic earnings formula, by December 31, 2014. Both benefit formulas allow for a lump sum distribution of vested benefits. Lump sum distributions totaled approximately $9.0 million and $7.0 million during 2014 and 2013, respectively, and did not require settlement accounting according to ASC 715.

Annual contributions to the plan are at least equal to the greater of either minimum funding requirements of ERISA or the accrued cost of the Plan, as required by the Missouri Public Service Commission. We also have a supplemental retirement program ("SERP") for designated officers of the Company, which we fund from Company funds as the benefits are paid.

Our net pension liability increased $20.6 million in 2014, which was recorded as an increase in regulatory assets as we believe it is probable of recovery through customer rates based on rate orders received in our jurisdictions. The increase in the liability is primarily due to a significant actuarial loss resulting from decreases in discount rates and the adoption of a new mortality table. Our contribution is estimated to be approximately $12.8 million for 2015. We expect future pension funding commitments to continue at least at the level of our accrued cost, as required by our regulator. The actual minimum funding requirements will be determined based on the results of the actuarial valuations and, in the case of 2016, the performance of our pension assets during 2015.

Expected benefit payments are as follows (in millions):

Year	Payments from Trust	Payments from Company Funds
2015	$25.0	$0.5
2016	22.0	0.5
2017	22.1	0.5
2018	20.8	0.5
2019	19.5	0.5
2020-2024	97.3	3.0

Other Postretirement Benefits (OPEB)

We provide certain healthcare and life insurance benefits to eligible retired employees, their dependents and survivors through trusts we have established. Participants generally become eligible for retiree healthcare benefits after reaching age 55 with 5 years of service. Employees hired after January 1, 2014 will be offered unsubsidized retiree healthcare benefits upon retirement.

Our net liability increased $19.9 million in 2014, which was recorded as an increase in regulatory assets as we believe it is probable of recovery through customer rates based on rate orders received in our jurisdictions. The increase in the liability is primarily due to a significant actuarial loss resulting from decreases in discount rates and the adoption of a new mortality table. Our funding policy is to contribute annually an amount at least equal to the actuarial cost of postretirement benefits. We expect to be required to fund approximately $5.0 million in 2015.

Estimated benefit payments are as follows (in millions):

Year	Payments from Trust	Expected Federal Subsidy	Payments from Company Funds
2015	$2.8	$0.3	$0.1
2016	3.1	0.4	0.2
2017	3.4	0.4	0.1
2018	3.7	0.5	0.2
2019	4.0	0.5	0.1
2020-2024	24.4	3.3	0.8

The following tables set forth the Company's benefit plans' projected benefit obligations, the fair value of the plans' assets and the funded status (in thousands).

Reconciliation of Projected Benefit Obligations:	Pension		SERP		OPEB	
	2014	2013	2014	2013	2014	2013
Benefit obligation at beginning of year	$ 225,131	$ 248,004	$ 7,108	$ 6,365	$ 85,332	$ 94,738
Service cost	6,467	7,454	153	135	2,601	2,941
Interest cost	10,819	10,063	387	315	4,360	3,827
Amendments	(7,753)		(45)		-	
Net actuarial (gain)/loss	36,742	(23,300)	1,890	604	20,347	(12,767)
Plan participant's contribution	-	-	-	-	850	949
Benefits and expenses paid	(19,527)	(17,090)	(338)	(311)	(3,897)	(4,396)
Federal subsidy	-	-	-	-	306	40
Benefit obligation at end of year	**$ 251,879**	**$ 225,131**	**$ 9,155**	**$ 7,108**	**$ 109,899**	**$ 85,332**

Reconciliation of Fair Value of Plan Assets:	Pension		SERP		OPEB	
	2014	2013	2014	2013	2014	2013
Fair value of plan assets at beginning of year	$186,547	$ 160,175	$ -	$ -	$ 79,098	$67,667
Actual return on plan assets – gain/(loss)	14,319	27,260	-	-	5,030	10,361
Employer contribution	11,335	16,202	-	-	2,258	4,360
Benefits paid	(19,527)	(17,090)	-	-	(3,707)	(4,229)
Plan participant's contribution	-	-	-	-	804	901
Federal subsidy	-	-	-	-	293	38
Fair value of plan assets at end of year	**$192,674**	**$186,547**	**$ -**	**$ -**	**$ 83,776**	**$79,098**

	Pension		SERP		OPEB	
Reconciliation of Funded Status:	2014	2013	2014	2013	2014	2013
Fair value of plan assets	$192,674	$ 186,547	$ -	$ -	$ 83,776	$ 79,098
Projected benefit obligations	(251,879)	(225,131)	(9155)	(7,108)	(109,899)	(85,332)
Funded status	**$(59,205)**	**$(38,584)**	**$ (9,155)**	**$ (7,108)**	**$(26,123)**	**$ (6,234)**

The employee pension plan accumulated benefit obligation at December 31, 2014 and 2013 is presented in the following table (in thousands):

	Pension Benefits		SERP	
	2014	2013	2014	2013
Accumulated benefit obligation	$227,928	$201,258	$ 7,160	$5,702

Amounts recognized in the balance sheet consist of (in thousands):

	Pension		SERP		OPEB	
	2014	2013	2014	2013	2014	2013
Accounts Payable and Accrued Liabilities	$ -	$ -	$ 481	$ 372	$ 139	$ 147
Pension and other postretirement benefit obligation	$59,205	$ 38,584	$ 8,674	$ 6,736	$ 25,984	$ 6,087

Net periodic benefit pension cost for 2014, 2013 and 2012, some of which is capitalized as a component of labor cost and some of which is deferred as a regulatory asset (see Note 3), is comprised of the following components (in thousands):

Net Periodic Pension Benefit Cost:	**Pension**			**OPEB**		
	2014	**2013**	**2012**	**2014**	**2013**	**2012**
Service cost	$ 6,467	$ 7,454	$ 6,261	$ 2,601	$ 2,941	$ 2,401
Interest cost	10,819	10,063	10,258	4,360	3,827	4,037
Expected return on plan assets	(13,105)	(12,428)	(12,309)	(4,801)	(4,353)	(4,135)
Amortization of prior service cost/(benefit)[1]	418	532	531	(1,011)	(1,011)	(1,011)
Amortization of actuarial loss[1]	6,611	10,445	7,935	967	2,261	1,661
Net periodic benefit cost	**$ 11,210**	**$ 16,066**	**$ 12,676**	**$ 2,116**	**$ 3,665**	**$ 2,953**

Net Periodic Pension Benefit Cost:	**SERP**		
	2014	**2013**	**2012**
Service cost	$ 153	$ 135	$ 51
Interest cost	387	315	263
Expected return on plan assets	-	-	-
Amortization of prior service cost/(benefit)t[1]	(8)	(8)	(8)
Amortization of actuarial loss[1]	504	567	389
Net periodic benefit cost	**$ 1,036**	**$ 1,009**	**$ 695**

[1]Amounts are amortized from our regulatory asset originally recorded upon recognizing our net pension liability on the balance sheet.

The tables below present other changes in plan assets and benefit obligations recognized in the regulatory asset accounts for the year (in thousands).

		Amount Recognized				
Regulatory Assets	**Beginning Balance 12/31/13**	**Current Year Actuarial Loss**	**Amortization of Actuarial Loss**	**Current Year Prior Service Credit**	**Amortization of Prior Service (Cost)/Credit**	**Ending Balance 12/31/14**
Pension	$ 56,709	35,529	(6,611)	(7,753)	(418)	$ 77,456
SERP	$ 4,188	1,890	(504)	(45)	8	$ 5,537
OPEB	$ 285	20,117	(967)	-	1,011	$ 20,446

		Amount Recognized			
Regulatory Assets	**Beginning Balance 12/31/12**	**Current Year Actuarial (Gain)/Loss**	**Amortization of Actuarial Loss**	**Amortization of Prior Service (Cost)/Credit**	**Ending Balance 12/31/13**
Pension	$ 105,818	(38,132)	(10,445)	(532)	$ 56,709
SERP	$ 4,143	604	(567)	8	$ 4,188
OPEB	$ 20,311	(18,776)	(2,261)	1,011	$ 285

The following table presents the amount of net actuarial gains / losses, transition obligations / assets and prior period service costs in regulatory assets not yet recognized as a component of net periodic benefit cost. It also shows the amounts expected to be recognized in the subsequent year. The following table presents those items for the employee pension plan and other benefits plan at December 31, 2014, and the subsequent twelve-month period (in thousands):

	Pension Benefits		SERP		OPEB	
	2014	Subsequent Period	2014	Subsequent Period	2014	Subsequent Period
Net actuarial loss	$ 84,178	$ 9,380	$ 5,595	$ 560	$ 23,030	$ 2,725
Prior service cost (benefit)	(6,722)	(630)	(58)	(43)	(2,584)	(1,011)
Total	**$ 77,456**	**$ 8,750**	**$ 5,537**	**$ 517**	**$ 20,446**	**$ 1,714**

The measurement date used to determine the pension and other postretirement benefits is December 31. The assumptions used to determine the benefit obligation and the periodic costs are as follows:

Weighted-average assumptions used to determine the benefit obligation as of December 31:

	Pension Benefits		OPEB	
	2014	2013	2014	2013
Discount rate	4.06%	4.90%	4.15%	5.00%
Rate of compensation increase	3.50%	3.50%	3.50%	3.50%

Weighted-average assumptions used to determine the net benefit cost (income) as of January 1:

	Pension Benefits			OPEB		
	2014	2013	2012	2014	2013	2012
Discount rate	4.90%	4.00%	4.70%	5.00%	4.11%	4.90%
Expected return on plan assets	7.75%	7.75%	7.90%	6.52%	6.52%	6.65%
Rate of compensation increase	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%

The expected long-term rate of return assumption was based on historical return and adjusted to estimate the potential range of returns for the current asset allocation. The assumed 2014 cost trend rate used to measure the expected cost of healthcare benefits and benefit obligation is 7.0%. Each trend rate decreases 0.50% through 2019 to an ultimate rate of 5.0% in 2019 and subsequent years.

The healthcare cost trend rate affects projected benefit obligations. A 1% change in assumed healthcare cost growth rates would have the following effects (in thousands):

	1% Increase	1% Decrease
Effect on total of service and interest cost	$ 1,395	$ (1,084)
Effect on post-retirement benefit obligation	$ 19,135	$ (14,983)

Fair value measurements of plan assets

See Note 15 for a discussion of fair value measurements. The Company believes that it is appropriate for the pension fund to assume a moderate degree of investment risk with diversification of fund assets among different classes (or types) of investments, as appropriate, as a means of reducing risk. Although the pension fund can and will tolerate some variability in market value and rates of return in order to achieve a greater long-term rate of return, primary emphasis is placed on preserving the pension fund's principal. Full discretion is delegated to the investment managers to carry out investment policy within stated guidelines. The guidelines and performance of the managers are monitored by the Company's Investment Committee. The following is a description of the valuation methodologies used for assets measured at fair value using significant other observable, or significant unobservable inputs.

Short-term investments: Valued at cost, which approximates fair value.

Common/Collective trusts: Valued at the fair value based on audited financials of the trusts.

U.S. corporate and foreign issue debt: Valued at quoted market prices when available in an active market. If quoted market prices are not available, then fair values are estimated by using pricing models, quoted prices of securities with similar characteristics, or discounted cash flows.

Equity long/short hedge funds: Valued at the net asset value reported in the annual audited financial statements and updated monthly based on changes in the value of the underlying funds reported by the fund manager.

Pension plan assets

We utilize fair value in determining the market-related values for the different classes of our pension plan assets. The market-related value is determined based on smoothing actual asset returns in excess of (or less than) expected return on assets over a 5-year period.

The Company's primary investment goals for pension fund assets are based around four basic elements:

1. Preserve capital,
2. Maintain a minimum level of return equal to the actuarial interest rate assumption,
3. Maintain a high degree of flexibility and a low degree of volatility, and
4. Maximize the rate of return while operating within the confines of prudence and safety.

Asset Allocation

We have adopted an investment strategy referred to as a de-risking glide path to increase the fixed income allocation as the plan's funded status improves. As the pension plan reaches set funded status milestones, the plan's assets will be rebalanced to shift more assets from equity to fixed income. Based on the plan's progress with this strategy, the target investment allocation for pension fund assets is approximately 72% equities and 28% fixed income securities. However, these allocations are permitted to vary within the following ranges: 60%-80% for equities and 20%-40% for fixed income securities. Money market funds are permitted within the fixed income category. Investment managers may generally hold up to 10% cash in their portfolios although this limit may be exceeded if market conditions warrant.

The following fair value hierarchy table presents information about the pension fund assets measured at fair value as of December 31, 2014 and December 31, 2013 (in thousands):

	Fair Value Measurements as of December 31, 2014				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**	**Percentage of Plan Assets**
Short term investments	$ -	$ 70	$ -	$ 70	0.0%
Equity securities					
Common collective trusts	-	91,530	-	91,530	47.5%
Fixed income					
Common collective trust	-	62,646	-	62,646	32.5%
Other types of investments					
Equity long/short hedge funds	-	-	38,428	38,428	20.0%
	$ -	$154,246	$ 38,428	$ 192,674	100.0%

	Fair Value Measurements as of December 31, 2013				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Percentage of Plan Assets
Short term investments	$ 74	$ -	$ -	$ 74	0.1%
Equity securities					
Common collective trusts	-	104,713	-	104,713	56.1%
Fixed income					
Common collective trust	-	45,031	-	45,031	24.1%
Other types of investments					
Equity long/short hedge funds	-		36,729	36,729	19.7%
	$ 74	$ 149,744	$ 36,729	$ 186,547	100.0%

Fair Value Measurements Using Significant Unobservable Inputs (Level 3) – December 31,

	2014	2013
	Equity long/short hedge funds	Equity long/short hedge funds
Beginning Balance, January 1,	$ 36,729	$ 28,885
Actual return on plan assets:		
Relating to assets still held at the reporting date	1,382	(356)
Relating to assets sold during the period	1,491	4,583
Purchases	9,700	26,500
Sales	(10,874)	(22,883)
Settlements	-	-
Transfers into and (out of) Level 3	-	-
Ending Balance, December 31,	$ 38,428	$ 36,729

Permissible Investments

Listed below are the investment vehicles specifically permitted:

Permissible Investments

Equity Oriented	Fixed Income Oriented and Real Estate
► Common Stocks	► Bonds (including US Government and Agencies)
► Preferred Stocks (minimum "A-rated" by Moody's or S&P)	► Corporate Bonds (minimum quality rating of Baa by Moody's or BBB by S&P)
► American Depository Receipts	► Comingled bond funds (25% max. allocation to high yield)
► Convertible Preferred Stocks	► Foreign Government Bonds
► Convertible Bonds	► GIC's, BIC's
► Covered Options	► Commercial Paper (rated A1 by S&P or P1 by Moody's)
► Hedged Equity Funds of Funds	► Certificates of Deposit in institutions with FDIC/FSLIC protection
	► Money Market Funds/Bank STIF Funds
	► Real Estate – Publicly Traded

The above assets can be held in commingled (mutual) funds as well as privately managed separate accounts.

Those investments prohibited by the Investment Committee without prior approval are:

Prohibited Investments Requiring Pre-approval	
► Privately Placed Securities	► Warrants
► Commodities Futures	► Short Sales
► Securities of Empire District (except in the hedged equity funds of funds or commingled funds)	► Index Options
► Restricted Stock	► Letter Stock

OPEB plan assets

The Company's primary investment goals for the component of the OPEB fund used to pay current benefits are liquidity and safety. The primary investment goals for the component of the OPEB fund used to accumulate funds to provide for payment of benefits after the retirement of plan participants are preservation of the fund with a reasonable rate of return. The target allocation for plan assets is 60% equities and 40% fixed income, although, at any given time, up to 10% of either category may be invested in cash equivalents. The 10% cash limitation may be exceeded if market conditions warrant. Allocations may also vary within the following ranges: 44%-76% equities and 36%-44% fixed income securities. The following fair value hierarchy table presents information about the OPEB fund assets measured at fair value as of December 31, 2014 and December 31, 2013 (in thousands):

	Fair Value Measurements as of December 31, 2014				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Percentage of Plan Assets
Equity securities					
Common collective trusts	$ -	$ 47,690	$ -	$ 47,690	56.9%
Fixed income					
Common collective trusts	-	33,708	-	33,708	40.2%
Other types of investments					
Common collective trusts	-	2,453	-	2,453	2.9%
	$ -	$ 83,851	$ -	$ 83,851	
Payable for securities purchased				(75)	0.0%
				$ 83,776	100%

	Fair Value Measurements as of December 31, 2013				
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total	Percentage of Plan Assets
Cash and cash equivalents	$ 1,317	$ -	$ -	$ 1,317	1.7%
Fixed income					
U.S. corporate debt	-	17,592	-	17,592	22.2%
Foreign debt	-	2,871	-	2,871	3.6%
Mutual funds – fixed income	8,325	-	-	8,325	10.5%
Equity securities					
U.S. equity	27,779	-	-	27,779	35.1%
International equity	9,316	-	-	9,316	11.8%
Mutual funds - equity	11,633	-	-	11,633	14.7%
	$ 58,370	$ 20,463	$ -	78,833	
Accrued interest & dividends				265	0.4%
				$ 79,098	100%

The Company's guideline in the management of this fund is to endorse a long-term approach, but not expose the fund to levels of volatility that might adversely affect the value of the assets. Full discretion is delegated to the investment managers to carry out investment policy within stated guidelines. The guidelines and performance of the managers are monitored by the Company's Investment Committee.

Permissible Investments

Listed below are the investment vehicles specifically permitted:

Permissible Investments

Equity	Fixed Income
► Common Stocks	► Cash-Equivalent Securities with a maturity of one-year or less, including: money market funds, US Government and Agency securities, certificates of deposit or banker's acceptances issued by domestic banks with FDIC protection and commercial paper rated A1 by S&P or P1 by Moody's
► Preferred Stocks	► Government Bonds
	► Money Market Funds / Bank STIF Funds
	► Certificates of Deposit in institutions with FDIC protection
	► Corporate Bonds (minimum quality rating of A Baa by Moody's or BBB by S&P at time of issuance)

The above assets can be held in commingled (mutual) funds as well as privately managed separate accounts.

Listed below are those investments prohibited by the Investment Committee:

Prohibited Investments

► Privately Placed Securities	► Margin Transactions
► Securities of Empire District	► Options (other than "covered call options")
► Derivatives	► Lettered or Restricted Stock
► Instrumentalities in violation of the Prohibited Transactions Standards of ERISA	► Any other investment security which, in the opinion of the investment manager produces an imprudent risk to the fund

Employee Stock Purchase Plan

Our Employee Stock Purchase Plan (ESPP) permits the grant to eligible employees of options to purchase common stock at 90% of the lower of market value at date of grant or at date of exercise. The lookback feature of this plan is valued at 90% of the Black-Scholes methodology plus 10% of the maximum subscription price. As of December 31, 2014 and 2013, there were 820,838 and 127,774 shares available for issuance in this plan, respectively.

	2014	2013	2012
Subscriptions outstanding at December 31,	57,369	60,413	70,850
Maximum subscription price	$21.43[(1)]	$ 19.58	$ 17.95
Shares of stock issued	56,942	68,099	65,919
Stock issuance price	$19.58	$ 17.95	$ 17.27

(1) Stock will be issued on the closing date of the purchase period, which runs from June 1, 2014 to May 31, 2015.

Assumptions for valuation of these shares are shown in the table below.

	2014	2013	2012
Weighted average fair value of grants	$ 3.07	$ 2.78	$ 3.19
Risk-free interest rate	0.10%	0.14%	0.17%
Dividend yield	4.30%	4.60%	5.00%
Expected volatility [(1)]	14.00%	14.00%	24.00%
Expected life in months	12	12	12
Grant date	6/2/14	6/1/13	6/1/12

(1) One-year historic volatility

401(k) Plan and ESOP

Our Employee 401(k) Plan and ESOP (the 401(k) Plan) allows participating employees to defer up to 25% of their annual compensation up to an Internal Revenue Service specified limit. For employees participating in the cash balance formula of the pension plan, discussed above, we match 100% of their deferrals, not to exceed 6% of the employee's eligible compensation. The first 3% of the matching contribution is made in shares of our common stock with the remaining portion made by contributing cash. For employees remaining with the traditional average annual basic earnings formula of the pension plan, we match 50% of their deferrals by contributing shares of our common stock, with such matching contributions not to exceed 3% of the employee's eligible compensation. We record the compensation expense at the time the quarterly matching contributions are made to the plan. At December 31, 2014 and 2013, there were 196,399 and 256,448 shares available to be issued, respectively.

	2014	2013	2012
Shares contributed	60,049	64,128	65,502

Deferred Compensation

Effective January 2015, we established a non-qualified Deferred Compensation Plan for the purpose of allowing executive officers who elect to participate in the qualifying cash balance option of the Pension plan to obtain retirement savings that are not available to them under the 401(k) plan.

8. EQUITY COMPENSATION

We have several stock-based awards and programs, which are described below. Performance-based restricted stock awards, time-vested restricted stock and stock options are valued as liability awards, in accordance with fair value guidelines. We allow employees to elect to have taxes in excess of the minimum statutory requirements withheld from their awards and, therefore, the awards are classified as liability instruments under the ASC guidance on share based payment. Awards treated as liability instruments must be revalued each period until settled, and cost is accrued over the requisite service period and adjusted to fair value at each reporting period until settlement or expiration of the award.

We recognized the following amounts in compensation expense and tax benefits for all of our stock-based awards and programs for the applicable years ended December 31 (in thousands):

	2014	2013	2012
Compensation expense	$ 3,688	$ 2,577	$ 1,863
Tax benefit recognized	1,359	929	649

Stock Incentive Plans

Our 2006 Stock Incentive Plan (the 2006 Incentive Plan), which was set to expire on December 31, 2015, was replaced by the 2015 Stock Incentive Plan (the 2015 Incentive Plan). The 2015 Incentive Plan was adopted by shareholders at the annual meeting on May 1, 2014 and provides for grants of up to 500,000 shares of common stock through January 2025. The 2015 Stock Incentive Plan permits (and the 2006 Incentive Plan permitted) grants of stock options and restricted stock to qualified employees and permits Directors and, if approved by the Compensation Committee of the Board of Directors, qualified employees to receive common stock in lieu of cash. Certain executive officers and other senior managers applied to receive annual incentive awards related to 2012, 2013 and 2014 performance in the form of Empire common stock rather than cash. These requests were granted by the Compensation Committee of the Board of Directors under the terms of our 2006 Stock Incentive Plan. The terms and conditions of any option or stock grant are determined by the Board of Directors Compensation Committee, within the provisions of these Stock Incentive Plans.

Time-Vested Restricted Stock Awards

Beginning in 2011, we began granting, to qualified individuals, time-vested restricted stock awards that vest after a three-year period, in lieu of stock options. No dividend rights accumulate during the vesting period. Time-vested restricted stock is valued at an amount equal to the fair market value of our common stock on the date of grant. If employment terminates during the vesting period because of death, retirement or disability, the participant is entitled to a pro-rata portion of the time-vested restricted stock awards such participant would otherwise have earned, which is distributed six months following the date of termination, with the remainder of the award forfeited. If employment is terminated during the vesting period for reasons other than those listed above, the time-vested restricted stock awards will be forfeited on the date of the termination, unless the Board of Directors' Compensation Committee determines, in its sole discretion, that the participant is entitled to a pro-rata portion of the award.

The fair value measurements for each grant year are noted in the following table:

	Fair Value of Grants Outstanding at December 31	
	2014	**2013**
Total unrecognized compensation cost (in millions)	$ 0.4	$ 0.2
Recognition period	1.1 years to 2.1 years	0.1 years to 2.1 years
Fair value	$26.82	$ 19.88

No shares of time-vested restricted stock were granted in 2012 as a result of the limitation on incentive compensation in effect in 2011 given our 2011 dividend suspension. A summary of time vested restricted stock activity under the plan for 2014, 2013 and 2012 is presented in the table below:

	2014		2013		2012	
	Number of Shares	Weighted Average Grant Date Fair Value	Number of Shares	Weighted Average Grant Date Fair Value	Number Of Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1,	24,900	$21.42	3,300	$21.84	3,433	$21.84
Granted	22,600	$22.40	21,600	$21.36	-	-
Distributed	(4,010)	$21.77	-	-	(133)	$20.13
Forfeited	(2,490)	$21.99	-	-	-	-
Outstanding at December 31,	41,000	$21.89	24,900	$21.42	3,300	$21.84
Vested during the year	6,500	$21.86	-	-	-	-

Performance-Based Restricted Stock Awards

Performance-based restricted stock awards are granted to qualified individuals consisting of the right to receive a number of shares of common stock at the end of the restricted period assuming performance criteria are met. The performance measure for the award is the total return to our shareholders over a three-year period compared with an investor-owned utility peer group. The threshold level of performance under the 2012, 2013 and 2014 grants was set at the 20th percentile level of the peer group, target at the 50th percentile level, and the maximum at the 80th percentile level. Shares would be earned at the end of the three-year performance period as follows: 100% of the target number of shares if the target level of performance is reached, 50% if the threshold is reached, and 200% if the percentile ranking is at or above the maximum, with the number of shares interpolated between these levels. However, no shares would be payable if the threshold level is not reached. The fair value of the outstanding restricted stock awards was estimated as of December 31, 2014, 2013 and 2012 using a Monte Carlo option valuation model. The assumptions used in the model for each grant year are noted in the following table:

	Fair Value of Grants Outstanding at December 31,		
	2014	**2013**	**2012**
Risk-free interest rate	0.25% to 0.67%	0.13% to 0.38%	0.16% to 0.25%
Expected volatility of Empire stock	14.5%	20.2%	20.6%
Expected volatility of peer group stock	12.4% to 24.8%	12.3% to 27.5%	12.4% to 29.2%
Expected dividend yield on Empire stock	3.5%	4.5%	4.9%
Expected forfeiture rates	3%	3%	3%
Plan cycle	3 years	3 years	3 years
Fair value percentage	140.0% to 157.0%	0.0% to 108.0%	18.0% to 96.0%
Weighted average fair value per share	$43.80	$18.47	$10.94

Non-vested performance-based restricted stock awards (based on target number) as of December 31, 2014, 2013 and 2012 and changes during the year ended December 31, 2014, 2013 and 2012 were as follows:

	2014		2013		2012	
	Number of Shares	Weighted Average Grant Date Fair Value	Number of Shares	Weighted Average Grant Date Fair Value	Number Of Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1,	47,200	$21.39	33,900	$20.25	37,400	$19.28
Granted	27,000	$22.40	26,300	$21.36	10,000	$20.97
Awarded	-	-	(4,460)	$18.36	(7,823)	$18.12
Not awarded	(10,900)	$21.84	(8,540)	$18.36	(5,677)	$18.12
Nonvested at December 31,	63,300	$21.74	47,200	$21.39	33,900	$20.25

At December 31, 2014 and 2013, unrecognized compensation expense related to estimated outstanding awards was $1.1 million and $0.5 million, respectively.

<u>Stock Options</u>

Beginning in 2011, we began issuing time-vested restricted stock in lieu of stock options and dividend equivalents. Prior to 2011 stock options were issued with an exercise price equal to the fair market value of the shares on the date of grant. They became exercisable after three years and expired ten years after the date granted. Dividend equivalent awards, under which dividend equivalents accumulated during the vesting period, were also issued to recipients of the stock options. Participants' options and dividend equivalents that were not vested were forfeited when participants left Empire, except for terminations of employment under certain specified circumstances. There were no stock options or dividend equivalents granted in 2014, 2013, or 2012, and all outstanding options were exercised prior to December 31, 2014.

Stock option grants vest upon satisfaction of service conditions. The cost of the awards is generally recognized over the requisite (explicit) service period. There were no outstanding options at December 31, 2014. The fair value of the outstanding options was estimated as of December 31, 2013 and 2012, under a Black-Scholes methodology. The assumptions used in the valuations are shown below:

	Fair Value of Grants Outstanding at December 31,		
	2014	2013	2012
Risk-free interest rate	-	0.10% to 0.38%	0.11% to 0.44%
Dividend yield	-	4.5%	4.9%
Expected volatility	-	24.0%	24.0%
Expected life in months	-	6.5 to 24.5	78
Market value	-	$22.69	$20.38
Weighted average fair value per option	-	$1.57	$1.34

A summary of option activity under the plan during the years ended December 31, 2014, 2013 and 2012 is presented below:

	2014		2013		2012	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
Outstanding at January 1,	112,500	$ 23.27	163,300	$ 22.13	190,300	$ 21.56
Granted	-	-		$ -	0	$ -
Exercised	112,500	$ 24.58	(50,800)	$ 21.78	(27,000)	$ 18.12
Outstanding at December 31,	-		112,500	$ 23.27	163,300	$ 22.13
Exercisable, end of year	-		112,500	$ 23.27	128,500	$ 23.15

The intrinsic value of the unexercised options is the difference between the Company's closing stock price on the last day of the period and the exercise price multiplied by the number of in-the-money options, had all option holders exercised their options on the last day of the period. The intrinsic value is zero if such closing price is less than the exercise price. The table below shows the aggregate intrinsic values at December 31, 2014, 2013, and 2012:

	2014	2013	2012
Aggregate intrinsic value (in millions)	-	Less than $0.1	$0.1
Weighted-average remaining contractual life of outstanding options	-	2.1 years	3.2 years
Range of exercise prices	-	$21.92 to $23.81	$18.36 to $23.81
Total unrecognized compensation expense (in millions) related to non-vested options and related dividend equivalents granted under the plan	-	-	Less than $0.1
Recognition period	-	-	1 month

Stock Unit Plan for Directors

Our Stock Unit Plan for directors (Stock Unit Plan) provides a stock-based compensation program for directors. This plan enhances our ability to attract and retain competent and experienced directors and allows the directors the opportunity to accumulate compensation in the form of common stock units. The Stock Unit Plan also provides directors the opportunity to convert previously earned cash retirement benefits to common stock units. All eligible directors who had benefits under the prior cash retirement plan converted their cash retirement benefits to common stock units.

As of December 31, 2014, a total of 900,000 shares were authorized under this plan. Each common stock unit earns dividends in the form of common stock units and can be redeemed for shares of common stock. The number of units granted annually is computed by dividing an annual credit (determined by the Compensation Committee) by the fair market value of our common stock on January 1 of the year the units are granted. Common stock unit dividends are computed based on the fair market value of our stock on the dividend's record date. We record the related compensation expense at the time we make the accrual for the directors' benefits as the directors provide services. Shares accrued to directors' accounts and shares available for issuance under this plan at December 31 are shown in the table below:

	2014	2013
Shares accrued to directors' accounts	164,085	154,402
Shares available for issuance	714,978	236,056

Units accrued for service and dividends as well as units redeemed for common stock at December 31 are shown in the table below:

	2014	2013	2012
Units accrued for service and dividends	30,765	34,252	30,426
Units redeemed for common stock	21,083	22,908	21,324

9. INCOME TAXES

Income tax expense components for the years ended December 31 are as follows (in thousands):

	2014	2013	2012
Current income taxes:			
Federal	$ (2,350)	$ 6,726	$ 1,552
State	(123)	2,495	708
TOTAL	(2,473)	9,221	2,260
Deferred income taxes:			
Federal	36,620	24,954	28,210
State	5,216	3,554	4,018
TOTAL	41,836	28,508	32,228
Investment tax credit amortization	(143)	(237)	(329)
TOTAL INCOME TAX EXPENSE	**$ 39,220**	**$ 37,492**	**$ 34,159**

Deferred Income Taxes

Deferred tax assets and liabilities are reflected on our consolidated balance sheets as follows (in thousands):

Deferred Income Taxes	December 31, 2014	December 31, 2013
Current deferred tax assets, net (1)	$ 19,200	$ 7,222
Non-current deferred tax liabilities, net	377,452	324,266
NET DEFERRED TAX LIABILITIES	**$ 358,252**	**$ 317,044**

(1) Current deferred tax assets are included in prepaid expenses and other on the balance sheets.

Temporary differences related to deferred tax assets and deferred tax liabilities are summarized as follows (in thousands):

Temporary Differences	December 31, 2014	December 31, 2013
Deferred tax assets:		
Plant related basis differences	$ 25,349	$ 23,344
Net operating loss (NOL)	22,000	-
Regulated liabilities related to income taxes	13,350	13,576
Disallowed plant costs	1,754	1,841
Gains on hedging transactions	1,260	1,324
Pensions and other post-retirement benefits	1,175	544
Carry forward of income tax credit	6,367	6,374
Other	1,633	1,633
Total deferred tax assets	$ 72,888	$ 48,636
Deferred tax liabilities:		
Depreciation, amortization and other plant related differences	$ 363,337	$ 297,175
Regulated assets related to income	37,180	37,806
Loss on reacquired debt	3,828	4,085
Amortization of intangibles	9,168	8,089
Deferred construction accounting costs	6,082	6,977
Other	11,545	11,548
Total deferred tax liabilities	431,140	365,680
NET DEFERRED TAX LIABILITIES	**$ 358,252**	**$ 317,044**

Effective Income Tax Rates

The difference between income taxes and amounts calculated by applying the federal legal rate to income tax expense for continuing operations were as follows:

Effective Income Tax Rates	2014	2013	2012
Federal statutory income tax rate	35.0%	35.0%	35.0%
Increase (decrease) in income tax rate resulting from:			
State income tax (net of federal benefit)	3.1	3.1	3.1
Investment tax credit amortization	(0.1)	(0.2)	(0.4)
Effect of ratemaking on property related differences	(1.7)	(1.1)	(0.2)
Other	0.6	0.3	0.5
EFFECTIVE INCOME TAX RATE	**36.9%**	**37.1%**	**38.0%**

We do not have any unrecognized tax benefits as of December 31, 2014. We did not recognize any significant interest or penalties in any of the periods presented. We do not expect any significant changes to our unrecognized tax benefits over the next twelve months.

The Tax Increase Prevention Act (the "Act") was signed into law on December 19, 2014. The Act restored several expired business tax provisions, including bonus depreciation for 2014. Our 2015 tax payments are expected to be higher than 2014 due to the expiration of bonus depreciation. However, we expect to utilize investment tax credits and net operating losses (NOLs) discussed below to partially offset the 2015 payments.

We generated $22.0 million of tax NOLs during 2014, mainly due to bonus depreciation. These losses may be carried back two years and are also available to offset future taxable income until 2034.

In 2010, we received $17.7 million of investment tax credits based on our investment in Iatan 2. We utilized $0.7 million and $9.0 million of these credits on our 2012 and 2013 tax returns, respectively. Due to the passage of the Act, we were unable to use these credits on our 2014 tax return. We expect to use the remaining credits on our 2015 tax return. The tax credits will have no significant income statement impact because they will flow to our customers as we amortize the tax credits over the life of the plant.

On September 13, 2013, the IRS and the Treasury Department released final regulations under Sections 162(a) and 263(a) on the deduction and capitalization of expenditures related to tangible property. These regulations apply to tax years beginning on or after January 1, 2014, and we plan to file a Form 3115 with the IRS with our 2014 income tax return to change our tax accounting method to comply with the regulations. It is anticipated that we will deduct approximately $33 million on our 2014 income tax return under IRS Code Section 481(a) as an adjustment required by the change in method of accounting. We plan to utilize the book capitalization method as allowable under the final regulations which we expect will have an immaterial impact on the effective tax rate.

10. COMMONLY OWNED FACILITIES

Iatan

We own a 12% undivided interest in the coal-fired Units No. 1 and No. 2 at the Iatan Generating Station located near Weston, Missouri, 35 miles northwest of Kansas City, Missouri, as well as a 3% interest in the site and a 12% interest in certain common facilities. We are entitled to 12% of each unit's available capacity and are obligated to pay for that percentage of the operating costs of the units. KCP&L and KCP&L Greater Missouri Operations Co. own 70% and 18% respectively, of Unit 1, and 54% and 18%, respectively, of Unit 2. KCP&L operates the units for the joint owners.

At December 31, 2014 and 2013, our property, plant and equipment accounts included the amounts in the following chart (in millions):

Iatan	2014	2013
Cost of ownership in plant in service	$ 373.3	$ 367.1
Accumulated Depreciation	$ 99.1	$ 91.1
Expenditures(1)	$ 27.8	$ 31.6

(1) Recognized in operating, maintenance, and fuel expenditures excluding depreciation expense.

State Line Combined Cycle Unit

We and Westar Generating, Inc., ("WGI"), a subsidiary of Westar Energy, Inc., share joint ownership of a nominal 500-megawatt combined cycle unit at the State Line Power Plant (the "State Line Combined Cycle Unit"). We are responsible for the operation and maintenance of the State Line Combined Cycle Unit, and are entitled to 60% of the available capacity and are responsible for approximately 60% of its costs. At December 31, 2014 and 2013, our property, plant and equipment accounts included the amounts in the following chart (in millions):

State Line Combined Cycle Unit	2014	2013
Cost of ownership in plant in service	$ 161.5	$ 163.3
Accumulated Depreciation	$ 40.0	$ 37.0
Expenditures[(1)]	$ 47.1	$ 52.6

[(1)] Recognized in operating, maintenance, and fuel expenditures excluding depreciation expense.

Plum Point Energy Station

We own a 7.52% undivided interest in the coal-fired Plum Point Energy Station located near Osceola, Arkansas. We are entitled to 7.52% of the station's capacity, and are obligated to pay for that percentage of the station's operating costs. At December 31, 2014 and 2013, our property, plant and equipment accounts included the amounts in the following chart (in millions):

Plum Point Energy Station	2014	2013
Cost of ownership in plant in service	$ 108.3	$ 108.2
Accumulated Depreciation	$ 9.4	$ 7.3
Expenditures[(1)]	$ 8.1	$ 11.3

[(1)] Recognized in operating, maintenance and fuel expenditures excluding depreciation expense.

All of the dollar amounts listed above represent our ownership share of costs.

11. COMMITMENTS AND CONTINGENCIES

We are a party to various claims and legal proceedings arising out of the normal course of our business. We regularly analyze this information, and provide accruals for any liabilities, in accordance with the guidelines presented in the ASC on accounting for contingencies. In the opinion of management, it is not probable, given the company's defenses, that the ultimate outcome of these claims and lawsuits will have a material adverse effect upon our financial condition, or results of operations or cash flows.

Coal, Natural Gas and Transportation Contracts

The following table sets forth our firm physical gas, coal and transportation contracts for the periods indicated as of December 31, 2014 (in millions).

	Firm physical gas and transportation contracts	Coal and coal transportation contracts
January 1, 2015 through December 31, 2015	$26.6	$26.2
January 1, 2016 through December 31, 2017	$42.9	$29.5
January 1, 2018 through December 31, 2019	$33.3	$22.8
January 1, 2020 and beyond	$49.6	-

We have entered into long and short-term agreements to purchase coal and natural gas for our energy supply and natural gas operations. Under these contracts, the natural gas supplies are divided into firm physical commitments and derivatives that are used to hedge future purchases. In the event that this gas cannot be used at our plants, the gas would be placed in storage. The firm physical gas and transportation commitments are detailed in the table above.

We have coal supply agreements and transportation contracts in place to provide for the delivery of coal to the plants. These contracts are written with Force Majeure clauses that enable us to reduce tonnages or cease shipments under certain circumstances or events. These include mechanical or electrical maintenance items, acts of God, war or insurrection, strikes, weather and other disrupting events. This reduces the risk we have for not taking the minimum requirements of fuel under the contracts. The minimum requirements for our coal and coal transportation contracts as of December 31, 2014 are detailed in the table above.

Purchased Power

We currently supplement our on-system (native load) generating capacity with purchases of capacity and energy from other entities in order to meet the demands of our customers and the capacity margins applicable to us under current pooling agreements and National Electric Reliability Council (NERC) rules.

The Plum Point Energy Station (Plum Point) is a 670-megawatt, coal-fired generating facility near Osceola, Arkansas. We own, through an undivided interest, 50 megawatts of the unit's capacity. We also have a long-term (30 year) agreement for the purchase of an additional 50 megawatts of capacity from Plum Point. Commitments under this agreement are approximately $289.9 million through August 31, 2039, the end date of the agreement. We have the option to purchase an undivided ownership interest in the 50 megawatts covered by the purchased power agreement in 2015. We evaluated this purchase option as part of our Integrated Resource Plan (IRP), which was filed with the MPSC on July 1, 2013. It is not currently our intention to exercise this option in 2015.

We have a 20-year purchased power agreement, which began on December 15, 2008, with Cloud County Windfarm, LLC, owned by EDP Renewables North America LLC, Houston, Texas to purchase the energy generated at the approximately 105-megawatt Phase 1 Meridian Way Wind Farm located in Cloud County, Kansas. We do not own any portion of the windfarm. Annual payments are contingent upon output of the facility and can range from zero to a maximum of approximately $14.6 million based on a 20-year average cost.

We also have a 20-year contract, which began on December 15, 2005, with Elk River Windfarm, LLC, owned by IBERDROLA RENEWABLES, Inc., to purchase the energy generated at the 150-megawatt Elk River Windfarm located in Butler County, Kansas. We do not own any portion of the windfarm. Annual payments are contingent upon output of the facility and can range from zero to a maximum of approximately $16.9 million based on a 20-year average cost.

Payments for these agreements are recorded as purchased power expenses, and, because of the contingent nature of these payments, are not included in the operating lease obligations shown below.

New Construction

In December 2014 we completed an environmental retrofit at our Asbury plant. The retrofit project included the installation of a pulse-jet fabric filter (baghouse), circulating dry scrubber and powder activated carbon injection system. This new equipment enables us to comply with the Mercury and Air Toxics Standard (MATS). Construction costs through December 31, 2014 were $110.9 million for the project to date, excluding AFUDC. Final cost is expected to be approximately $112 million, excluding AFUDC.

We also have in place a contract with a third party vendor to complete engineering, procurement, and construction activities at our Riverton plant to convert Riverton Unit 12 from a simple cycle combustion turbine to a combined cycle unit. The conversion will include the installation of a heat recovery steam generator (HRSG), steam turbine generator, auxiliary boiler, cooling tower, and other auxiliary equipment. The Air Emission Source Construction Permit necessary for this project was issued by Kansas Department of Health and Environment on July 11, 2013. This conversion is currently scheduled to be completed in mid-2016 at a cost estimated to range from $165 million to $175 million, excluding AFUDC. This amount is included in our five-year capital expenditure plan. Construction costs, consisting of pre-engineering, site preparation activities and contract costs incurred project to date through December 31, 2014 were $88.5 million, excluding AFUDC.

See "Environmental Matters" below for more information on both of these projects.

Leases

We have purchased power agreements with Cloud County Windfarm, LLC and Elk River Windfarm, LLC, which are considered operating leases for GAAP purposes. Details of these agreements are disclosed in the Purchased Power section of this note.

We also currently have short-term operating leases for two unit trains to meet coal delivery demands, for garage and office facilities for our electric segment and for one office facility related to our gas segment. In addition, we have capital leases for certain office equipment and 108 railcars to provide coal delivery for our ownership and purchased power agreement shares of the Plum Point generating facility.

The gross amount of assets recorded under capital leases total $5.3 million at December 31, 2014.

Our lease obligations over the next five years are as follows (in thousands):

	Capital Leases	Operating Leases
2015	$ 553	$ 730
2016	549	720
2017	547	682
2018	547	645
2019	546	485
Thereafter	3,006	-
Total minimum payments	**5,748**	**$ 3,262**
Less amount representing interest	1,581	
Present value of net minimum lease payments	**$ 4,167**	

Expenses incurred related to operating leases were $0.8 million, $0.8 million and $0.9 million for 2014, 2013, and 2012, respectively, excluding payments for wind generated purchased power agreements. The accumulated amount of amortization for our capital leases was $1.5 million and $1.3 million at December 31, 2014 and 2013, respectively.

Environmental Matters

We are subject to various federal, state, and local laws and regulations with respect to air and water quality and with respect to hazardous and toxic materials and hazardous and other wastes, including their identification, transportation, disposal, record-keeping and reporting, as well as remediation of contaminated sites and other environmental matters. We believe that our operations are in material compliance with present environmental laws and regulations. Environmental requirements have changed frequently and become more stringent over time. We expect this trend to continue. While we are not in a position to accurately estimate compliance costs for any new requirements, we expect any such costs to be material, although recoverable in rates.

Electric Segment

The Federal Clean Air Act (CAA) and comparable state laws regulate air emissions from stationary sources such as electric power plants through permitting and/or emission control and related requirements. These requirements include maximum emission limits on our facilities for sulfur dioxide (SO2), particulate matter, nitrogen oxides (NOx), carbon monoxide (CO), and hazardous air pollutants including mercury. In the future they will include limits on greenhouse gases (GHG) such as carbon dioxide (CO_2).

Compliance Plan

In order to comply with current and forthcoming environmental regulations, we are taking actions to implement our compliance plan and strategy (Compliance Plan). The Mercury Air Toxic Standards (MATS) and the Clean Air Interstate Rule (CAIR), replaced by the Cross State Air Pollution Rule (CSAPR), which we discuss further below, are the drivers behind our Compliance Plan and its implementation schedule. The MATS require reductions in mercury, acid gases and other emissions considered hazardous air pollutants (HAPS). They became effective in April 2012 and require full compliance by April 16, 2015 (with flexibility for extensions for reliability reasons). The CSAPR was first proposed by the Environmental Protection Agency (EPA) in July 2010 as a replacement of CAIR and came into effect on January 1, 2015. We anticipate compliance costs associated with the MATS, CAIR and CSAPR regulations to be recoverable in our rates.

Our Compliance Plan largely follows the preferred plan presented in our Integrated Resource Plan (IRP), filed in mid-2013 with the MPSC. As described above under New Construction, the process of installing a scrubber, fabric filter, and powder activated carbon injection system at our Asbury plant has been completed. This addition required the retirement of Asbury Unit 2, a steam turbine rated at 14 megawatts that was used for peaking purposes. Asbury Unit 2 was retired on December 31, 2013.

In September 2012, we completed the transition of our Riverton Units 7 and 8 from operation on coal and natural gas to operation solely on natural gas. Riverton Unit 7 was permanently removed from service on June 30, 2014. Riverton Unit 8 and Riverton Unit 9, a small combustion turbine that requires steam from Unit 8 for start-up, are planned to be retired upon the conversion of Riverton Unit 12, a simple cycle combustion turbine, to a combined cycle unit. This conversion is currently scheduled to be completed in mid-2016.

See “New Construction” above for project costs for both of these projects.

<u>*Air Emissions*</u>

The CAA regulates the amount of NOx and SO2 an affected unit can emit. As currently operated, each of our affected units is in compliance with the applicable NOx and SO2 limits. Through the end of 2014, NOx emissions were regulated by the CAIR and National Ambient Air Quality Standard (NAAQS) rules for ozone (discussed below). Beginning January 1, 2015, NOx emissions are regulated by CSAPR and NAAQS rules for ozone. Through the end of 2014, SO2 emissions were regulated by the Title IV Acid Rain Program and the CAIR. Beginning January 1, 2015, SO2 emissions are regulated by the Title IV Acid Rain Program and the CSAPR.

CAIR:

The CAIR generally calls for fossil-fueled power plants greater than 25 megawatts to reduce emission levels of SO2 and/or NOx in 28 eastern states and the District of Columbia, including Missouri, where our Asbury, Energy Center, State Line and Iatan Units No. 1 and No. 2 are located. Kansas was not included in CAIR and our Riverton Plant was not affected. Arkansas, where our Plum Point Plant is located, was included for ozone season NOx but not for SO2. At this time we believe we are in compliance with CAIR, which was in its final year in 2014.

CSAPR:

The CSAPR requires 23 states to reduce annual SO2 and NOx emissions to help downwind areas attain NAAQS for fine particulate matter. 25 states are required to reduce ozone season NOx emissions to help downwind states attain NAAQS for ozone. The CSAPR NOx annual program impacts our Missouri and Kansas units while the CSAPR NOx ozone season program impacts our units in these two states plus our unit in Arkansas.

The CSAPR divides the states required to reduce SO2 into two groups. Both groups must reduce their SO2 emissions in Phase 1. Group 1 states, which include our sources in Missouri and Arkansas, must make additional SO2 reductions for Phase 2 in order to eliminate their significant contribution to air quality problems in downwind areas. Empire’s units in Kansas are in Group 2 of the CSAPR SO2 program.

Under the CSAPR Program, in our most current five-year business plan (2015-2019), which assumes normal operations while maintaining compliance with permit conditions, we anticipate that it may be economically beneficial to purchase allowances for some of these pollutants if needed, but at the time of this writing the allowance markets have not been fully developed. We are in position to comply with CSAPR in 2015.

Mercury Air Toxics Standard (MATS):

As described above, the MATS standard became effective in April 2012, and requires compliance by April 2015 (with flexibility for extensions for reliability reasons). For all existing and new coal-fired electric utility steam generating units (EGUs), the MATS standard will be phased in over three years, and allows states the ability to give facilities a fourth year to comply. On March 28, 2013, the EPA finalized updates to certain emission limits for new power plants under the MATS. The new standards affect only new coal and oil-fired power plants that will be built in the future. The update does not change the final emission limits or other requirements for existing power plants. We are in position to comply with MATS in 2015.

National Ambient Air Quality Standards (NAAQS):

Under the CAA, the EPA sets NAAQS for certain emissions considered harmful to public health and the environment, including particulate matter (PM), NOx, CO, SO2, and ozone which result from fossil fuel combustion. Our facilities are currently in compliance with all applicable NAAQS.

In January 2013, the EPA finalized the revised PM 2.5 primary annual standard at 12 ug/m^3 (micrograms per cubic meter of air). States are required to meet the primary standard in 2020. The standard should have no impact on our existing generating fleet because the regional ambient monitor results are below the PM 2.5 required level. However, the PM 2.5 standards could impact future major modifications/construction projects that require additional permits.

Ozone, also called ground level smog, is formed by the mixing of NOx and Volatile Organic Compounds (VOCs) in the presence of sunlight. Based on the current standard, our service territory is designated as attainment, meaning that it is in compliance with the standard. A revised ozone NAAQS was proposed by the EPA on November 25, 2014 and the final rule is expected in October 2015. We believe this revised Ozone NAAQS would affect our region but it's too early to determine what, if any, impact it would have on our generating plants at this time.

Greenhouse Gases (GHGs):

As the EPA began to prepare for future regulations, GHG emissions have been reported for several years under the Mandatory GHG Reporting Rule. EDE and EDG's GHG emissions for each year, since 2013, have been reported to the EPA as required.

A series of actions and decisions including the Tailoring Rule, which regulates carbon dioxide and other GHG emissions from certain stationary sources, have further set the foundation for the regulation of GHGs. However, because of the uncertainties regarding the final outcome of the GHG regulations (discussed below), the ultimate cost of compliance cannot be determined at this time. In any case, we expect the cost of complying with any such regulations to be recoverable in our rates.

In April 2012, the EPA proposed a Carbon Pollution Standard for new power plants to limit the amount of carbon emitted by EGUs. This standard was rescinded, and a re-proposal of standards of performance for affected fossil fuel-fired EGUs was published in January 2014. The proposed rule applies only to new EGUs and sets separate standards for natural gas-fired combustion turbines and for fossil fuel-fired utility boilers. The proposal would not apply to existing units, including modifications such as those required to meet other air pollution standards which are currently being undertaken at our Asbury facility and at the Riverton facility with the conversion of simple cycle Unit 12 to combined cycle. The final rule is expected in the summer of 2015.

On June 2, 2014, the EPA released the proposed rule for limiting carbon emissions from existing power plants. The "Clean Power Plan" requires a 30% carbon emission reduction from 2005 baseline levels by 2030 and requires fossil-fuel fired power plants across the nation, including those in Empire's fleet, to meet state-specific goals to lower carbon levels. The EPA has identified four building block strategies to achieve the best system of emission reduction (BSER). Included in these strategies are the following: efficiency improvements at fossil fuel power plants; using lower-emitting sources (such as natural gas combined cycle units); using more renewables and keeping nuclear sources; and using power more efficiently. States will use the building blocks to craft their compliance plans or may work with other states in developing a regional approach to compliance, in which case additional time is given for implementation.

The EPA is scheduled to issue the final rule for existing power plants by summer of 2015. Each state must submit its initial compliance plan by the summer of 2016 with additional time available by request until the summer of 2017 for a single state or the summer of 2018 for a multi-state approach. The EPA received greater than 2 million public comments by the December 1, 2014 closure of the comment period. State, federal and industry representatives voiced their concerns with the regulation as written and the potential impact on electric grid reliability and the cost to implement. State and industry representatives including Empire continue to evaluate potential paths forward if the rule is finalized as proposed by the EPA.

Also, on June 2, 2014, the EPA released the proposed carbon pollution standards for modified and reconstructed stationary EGUs. The proposed rule focuses on electric utility steam generating units and natural gas-fired stationary combustion turbines. The comment period ended October 16, 2014 and the EPA anticipates issuing a final rule in June 2015.

Water Discharges

We operate under the Kansas and Missouri Water Pollution Plans pursuant to the Federal Clean Water Act (CWA). Our plants are in material compliance with applicable regulations and have received all necessary discharge permits.

The Riverton Units 7 and 8 and Iatan Unit 1, which utilize once-through cooling water, were affected by regulations for Cooling Water Intake Structures issued by the EPA under the CWA Section 316(b) Phase II. In 2007, the United States Court of Appeals remanded key sections of these CWA regulations to the EPA. The EPA suspended the regulations. Following a series of court approved delays, the EPA published the final rule on August 15, 2014 with an effective date of October 14, 2014. Court challenges are expected. We expect the regulations to have a limited impact at Riverton given the planned retirement of unit 8 scheduled in 2016. A new intake structure design and cooling tower will be constructed as part of the Unit 12 conversion at Riverton. Impacts at Iatan 1 could range from flow velocity reductions or traveling screen modifications for fish handling to installation of a closed cycle cooling tower retrofit. Our new Iatan Unit 2 and Plum Point Unit 1 are covered by the proposed regulation, but were constructed with cooling towers, the proposed Best Technology Available. We expect them to be unaffected or minimally affected by the final rule.

Surface Impoundments

We own and maintain a coal ash impoundment located at our Asbury Power Plant. Additionally, we own a 12% interest in a coal ash impoundment at the Iatan Generating Station and a 7.52% interest in a coal ash impoundment at Plum Point. As a result of the transition from coal to natural gas fuel for Riverton Units 7 and 8, the former Riverton ash impoundment has been capped and closed. Final closure as an industrial (coal combustion waste) landfill was approved on June 30, 2014 by the Kansas Department of Health and Environment (KDHE).

On April 19, 2013, the EPA signed a notice of proposed rulemaking to revise its wastewater effluent limitation guidelines and standards under the CWA for coal-fired power plants. The proposal calls for updates to operating permits beginning in July 2017. Once the new guidelines are issued, the EPA and states would incorporate the new standards into wastewater discharge permits, including permits for coal ash impoundments. We do not have sufficient information at this time to estimate additional costs that might result from any new standards. All of our coal ash impoundments are compliant with existing state and federal regulations.

In June 2010, the EPA proposed to regulate coal combustion residuals (CCRs) under the Federal Resource Conservation and Recovery Act (RCRA). In the proposal, the EPA presented two options: (1) regulation of CCR under RCRA subtitle C as a hazardous waste and (2) regulation of CCR under RCRA subtitle D as a non-hazardous waste. On December 19, 2014 the EPA finalized the requirements under the subtitle D solid waste provisions. We expect compliance to result in the need to construct a new landfill and the conversion of existing ash handling from a wet to a dry system(s) at a potential cost of up to $15 million at our Asbury Power Plant. This preliminary estimate was developed before the rule was finalized and will be updated to conform to the final rule. We expect resulting costs to be recoverable in our rates.

We have received preliminary permit approval in Missouri for a new utility waste landfill adjacent to the Asbury plant. Our Detailed Site Investigation (DSI) has been completed and was submitted to MDNR for review and approval in on January 21, 2015. Receipt of the final construction permit for the waste landfill is expected in early 2016.

Renewable Energy

On November 4, 2008 Missouri voters approved the Clean Energy Initiative (Proposition C) which currently requires Empire and other investor-owned utilities in Missouri to generate or purchase electricity from renewable energy sources, such as solar, wind, biomass and hydro power, or purchase Renewable Energy Credits (RECs), in amounts equal to at least 5% of retail sales in 2014, increasing to at least 15% by 2021. We are currently in compliance with this regulatory requirement as a result of generation from our Ozark Beach Hydroelectric Project and purchased power agreements with Cloud County Windfarm, LLC, located in Cloud County, Kansas, and Elk River Windfarm, LLC, located in Butler County, Kansas. Proposition C also requires that 2% of the energy from renewable energy sources must be solar; however, we believed that we were exempted by statute from the solar requirement. On January 20, 2013 the Earth Island Institute, d/b/a Renew Missouri, and others challenged our solar exemption by filing a complaint with the MPSC. The MPSC dismissed the complaint and Renew Missouri filed a notice of appeal seeking review by the Missouri Supreme Court. On February 10, 2015 the Missouri Supreme Court issued an opinion holding that the legislature had the authority to adopt the statute providing the exemption but reversed the MPSC's holding that the two laws could be harmonized. The statute providing the exemption (which was enacted in August 2008) was impliedly repealed by the adoption of Proposition C because it conflicted with the latter law. We believe the matter will return to the MPSC for further action. While we are not in a position to accurately estimate the impact of this requirement, we expect any future costs to be recoverable in rates.

Kansas established a renewable portfolio standard (RPS), effective November 19, 2010. It requires 10% of our Kansas retail customer peak capacity requirements to be sourced from renewables in 2012, increasing to 15% by 2016, and to 20% by 2020. We are currently in compliance with this regulatory requirement as a result of purchased power agreements with Cloud County Windfarm, LLC, located in Cloud County, Kansas and Elk River Windfarm, LLC, located in Butler County, Kansas.

12. SEGMENT INFORMATION

We operate our business as three segments: electric, gas and other. As part of our electric segment, we also provide water service to three towns in Missouri. The Empire District Gas Company is our wholly-owned subsidiary formed to provide gas distribution service in Missouri. The other segment consists of our non-regulated businesses which is primarily our fiber optics business.

The tables below present statement of income information, balance sheet information and capital expenditures of our business segments.

	For the year ended December 31, 2014				
	Electric	Gas	Other	Eliminations	Total
Statement of Income Information:					
Revenues[1]	$ 592,491	$ 51,842	$ 9,302	$ (1,305)	$ 652,330
Depreciation and amortization	67,534	3,760	1,891	-	73,185
Federal and state income taxes	35,737	1,840	1,643	-	39,220
Operating income	90,488	6,775	2,736	-	99,999
Interest income	37	25	21	(32)	51
Interest expense	37,911	3,861	-	(32)	41,740
Income from AFUDC (debt and equity)	9,833	84	-	-	9,917
Income from continuing operations	$ 61,467	$ 2,965	$ 2,671	$ -	$ 67,103
Capital Expenditures	$ 212,866	$ 7,836	$ 2,151	$ -	$ 222,853

(1) The Electric Segment includes SPP Integrated Marketplace net revenues of $41.9 million.

	2013				
	Electric	Gas	Other	Eliminations	Total
Statement of Income Information:					
Revenues	$ 536,413	$ 50,041	$ 9,147	$ (1,271)	$ 594,330
Depreciation and amortization	63,659	3,709	1,938	-	69,306
Federal and state income taxes	34,478	1,484	1,530	-	37,492
Operating income	90,984	6,194	2,485	-	99,663
Interest income	537	115	8	(94)	566
Interest expense	37,683	3,890	-	(94)	41,479
Income from AFUDC (debt and equity)	5,910	30	-	-	5,940
Income from continuing operations	$ 58,603	$ 2,355	$ 2,487	$ -	$ 63,445
Capital Expenditures	$ 153,401	$ 4,419	$ 2,388	$ -	$ 160,208

	2012				
	Electric	Gas	Other	Eliminations	Total
Statement of Income Information:					
Revenues	$ 510,653	$ 39,849	$ 7,187	$ (592)	$ 557,097
Depreciation and amortization	55,312	3,598	1,537	-	60,447
Federal and state income taxes	32,266	789	1,104	-	34,159
Operating income	89,445	5,005	1,771	-	96,221
Interest income	946	323	7	(304)	972
Interest expense	37,866	3,905	-	(304)	41,467
Income from AFUDC (debt and equity)	1,918	10	-	-	1,928
Income from continuing operations	$ 52,631	$ 1,256	$ 1,794	$ -	$ 55,681
Capital Expenditures	$ 140,117	$ 3,571	$ 2,599	$ -	$ 146,287

Balance Sheet Information:	Electric	Gas (1)	December 31, 2014 Other	Eliminations	Total
Total assets	$ 2,271,539	$ 130,856	$ 34,655	$ (46,794)	$ 2,390,256

Balance Sheet Information:	Electric	Gas (1)	December 31, 2013 Other	Eliminations	Total
Total assets	$ 2,034,234	$ 123,736	$ 31,306	$ (44,231)	$ 2,145,045

(1) Includes goodwill of $39,492 at December 31, 2014 and 2013.

13. SELECTED QUARTERLY INFORMATION (UNAUDITED)

The following is a summary of quarterly results for 2014 and 2013 (dollars in thousands except per share amounts):

	Quarters			
Quarterly Results for 2014	**First**	**Second**	**Third**	**Fourth**
Operating revenues(1)	$ 179,673	$ 149,782	$ 171,512	$ 151,363
Operating income	$ 29,488	$ 19,502	$ 31,709	$ 19,300
Net Income	$ 20,905	$ 11,194	$ 23,892	$ 11,112
Basic and Diluted Earnings Per Share	$ 0.48	$ 0.26	$ 0.55	$ 0.26

(1) Operating revenue for the first, second, third and fourth quarters of 2014 include SPP IM net revenues of $6.2 million, $16.5 million, $11.5 million, and $7.5 million, respectively.

	Quarters			
Quarterly Results for 2013	**First**	**Second**	**Third**	**Fourth**
Operating revenues	$ 151,140	$ 136,646	$ 157,486	$ 149,058
Operating income	$ 21,858	$ 21,110	$ 32,896	$ 23,799
Net Income	$ 12,630	$ 11,658	$ 23,996	$ 15,162
Basic and Diluted Earnings Per Share	$ 0.30	$ 0.27	$ 0.56	$ 0.35

The sum of the net income and quarterly earnings per share of common stock may not equal the net income and earnings per share of common stock as computed on an annual basis due to rounding.

14. RISK MANAGEMENT AND DERIVATIVE FINANCIAL INSTRUMENTS

We engage in hedging activities in an effort to minimize our risk from the volatility of natural gas prices and power cost risk associated with exposure to congestion costs. We enter into both physical and financial contracts with counterparties relating to our future natural gas requirements that lock in prices (with respect to a range of predetermined percentages of our expected future natural gas needs) in an attempt to lessen the volatility in our fuel expenditures and gain cost predictability.

We began acquiring Transmission Congestion Rights (TCR) in 2013 in an effort to mitigate the cost of power we purchase from the SPP IM due to congestion exposure. TCRs entitle the holder to a stream of revenues (or charges) based on the day-ahead congestion on the transmission path. TCRs can be purchased or self-converted using rights allocated based on prior investments made in the transmission system. We recognize that if risk is not timely and adequately balanced or if counterparties fail to perform contractual obligations, actual results could differ materially from intended results.

All derivative instruments are recognized at fair value on the balance sheet. The unrealized losses or gains from derivatives used to hedge our fuel and purchased power costs in our electric segment are recorded in regulatory assets or liabilities. All gains and losses from derivatives related to the gas segment are also recorded in regulatory assets or liabilities. This is in accordance with the Accounting Standards Codification (ASC) guidance on regulated operations, given that those gains or losses are probable of refund or recovery, respectively, through our fuel adjustment mechanisms.

Risks and uncertainties affecting the determination of fair value include: market conditions in the energy industry, especially the effects of price volatility, regulatory and global political environments and requirements, fair value estimations on longer term contracts, the effectiveness of the derivative instruments in hedging the change in fair value of the hedged item, estimating underlying fuel demand and counterparty ability to perform. If we estimate that we have overhedged forecasted demand, the gain or loss on the overhedged portion will be recognized immediately as fuel and purchased power expense in our Consolidated Statement of Income and subject to our fuel adjustment mechanism.

As of December 31, 2014 and 2013, we have recorded the following assets and liabilities representing the fair value of derivative financial instruments held as of December 31, (in thousands):

ASSET DERIVATIVES		**2014**	**2013**
Non-designated hedging instruments due to regulatory accounting	**Balance Sheet Classification**	**Fair Value**	**Fair Value**
Natural gas contracts, gas segment	Current assets	$ -	$ 35
	Non-current assets and deferred charges- Other	-	-
Natural gas contracts, electric segment	Current assets	1	467
	Non-current assets and deferred charges- Other	-	41
Transmission congestion rights, electric segment	Current assets	3,900	1,967
Total derivatives assets		**$ 3,901**	**$ 2,510**

LIABILITY DERIVATIVES		**2014**	**2013**
Non-designated as hedging instruments due to regulatory accounting	**Balance Sheet Classification**	**Fair Value**	**Fair Value**
Natural gas contracts, gas segment	Current liabilities	$ 476	$ 8
	Non-current liabilities and deferred credits	-	-
Natural gas contracts, electric segment	Current liabilities	5,993	1,881
	Non-current liabilities and deferred credits	3,243	2,799
Transmission congestion rights, electric segment	Current liabilities	-	-
Total derivatives liabilities		**$ 9,712**	**$ 4,688**

Electric

At December 31, 2014, approximately $6.0 million of unrealized losses are applicable to financial instruments which will settle within the next twelve months.

There were no “mark-to-market” pre-tax gains/ (losses) from ineffective portions of our hedging activities for the electric segment for the years ended December 31, 2014 and 2013, respectively.

The following tables set forth “mark-to-market” pre-tax gains/ (losses) from non-designated derivative instruments for the electric segment for each of the years ended December 31 (in thousands):

Non-Designated Hedging Instruments – Due to Regulatory Accounting Electric Segment	Balance Sheet Classification of Gain/(Loss) on Derivative	Amount of Gain/(Loss) Recognized on Balance Sheet	
		2014	2013
Commodity contracts – electric segment	Regulatory (assets)/liabilities	$ (6,780)	$ (338)
Transmission congestion rights – electric segment	Regulatory (assets)/liabilities	12,958	1,967
Total – Electric Segment		**$ 6,178**	**$ 1,629**

Non-Designated Hedging Instruments – Due to Regulatory Accounting Electric Segment	Statement of Operations Classification of Loss on Derivative	Amount of Gain/(Loss) Recognized in Income on Derivative	
		2014	2013
Commodity contracts	Fuel and purchased power expense	$ (1,659)	$ (2,725)
Transmission congestion rights – electric segment	Fuel and purchased power expense	11,106	81
Total – Electric Segment		**$ 9,447**	**$ (2,644)**

We also enter into fixed-price forward physical contracts for the purchase of natural gas, coal and purchased power. These contracts are not subject to fair value accounting because they qualify for the normal purchase normal sale exemption. We have a process in place to determine if any future executed contracts that otherwise qualify for the normal purchase normal sale exception contain a price adjustment feature and will account for these contracts accordingly.

At December 31, 2014, the following volumes and percentages of our anticipated volume of natural gas usage for our electric operations for 2015 and the next four years are hedged at the following average prices per Dekatherm (Dth):

Year	% Hedged	Dth Hedged Physical	Dth Hedged Financial	Average Price
2015	63%	1,550,000	4,510,000	$4.351
2016	43%	1,976,000	2,100,000	$4.103
2017	20%	782,900	1,300,000	$4.133
2018	11%	456,000	500,000	$4.202
2019	-	-	-	-

We utilize the following procurement guidelines for our electric segment, allowing the flexibility to hedge up to 100% of the current year's and 80% of any future year's expected requirements while being cognizant of volume risk. The 80% guideline is an annual target and volumes up to 100% can be hedged in any given month. For years beyond year four, additional factors of long term uncertainty (including with respect to required volumes and counterparty credit) are also considered.

Year	End of Year Minimum % Hedged
Current	Up to 100%
First	60%
Second	40%
Third	20%
Fourth	10%

At December 31, 2014, the following transmission congestion rights (TCR) have been obtained from TCR auctions to hedge congestion costs in the SPP Integrated Marketplace:

Year	Monthly MWH Hedged	$ Value
2015	3,483	$ 3,899,526

Gas

We attempt to mitigate our natural gas price risk for our gas segment by a combination of (1) injecting natural gas into storage during the off-heating season months, (2) purchasing physical forward contracts and (3) purchasing financial derivative contracts. We target to have 95% of our storage capacity full by November 1 for the upcoming winter heating season. As the winter progresses, gas is withdrawn from storage to serve our customers. As of December 31, 2014 we had 1.2 million Dths in storage on the three pipelines that serve our customers. This represents 58% of our storage capacity.

The following table sets forth our long-term hedge strategy of mitigating price volatility for our customers by hedging a minimum of expected gas usage for the current winter season and the next two winter seasons by the beginning of the ACA year at September 1 and illustrates our hedged position as of December 31, 2014 (Dth in thousands).

Season	Minimum % Hedged	Dth Hedged Financial	Dth Hedged Physical	Dth in Storage	Actual % Hedged
Current	50%	430,000	341,000	1,178,367	97%
Second	Up to 50%	-	-	-	-
Third	Up to 20%	-	-	-	-

A Purchased Gas Adjustment (PGA) clause is included in our rates for our gas segment operations, therefore, we mark to market any unrealized gains or losses and any realized gains or losses relating to financial derivative contracts to a regulatory asset or regulatory liability account on our balance sheet.

The following table sets forth "mark-to-market" pre-tax gains/ (losses) from derivatives not designated as hedging instruments for the gas segment for the years ended December 31 (in thousands):

Non-Designated Hedging Instruments Due to Regulatory Accounting – Gas Segment	Balance Sheet Classification of Loss on Derivative	Amount of Loss Recognized on Balance Sheet	
		2014	2013
Commodity contracts	Regulatory assets	$ (511)	$ (5)
		-	
Total – Gas Segment		**$ (511)**	**$ (5)**

Contingent Features

Certain of our derivative instruments contain provisions that are triggered if we fail to maintain an investment grade credit rating with any relevant credit rating agency. If our debt were to fall below investment grade, the counterparties to the derivative instruments could request increased collateralization on derivative instruments in net liability positions. We had no derivative instruments with the credit-risk-related contingent features in a net liability position on December 31, 2014 and have posted no collateral in the normal course of business. Amounts reported as margin deposit assets represent our funds held on deposit for our NYMEX contracts with our broker and other financial contracts with other counterparties that resulted from us exceeding agreed-upon credit limits established by the counterparties. The following table depicts our margin deposit assets at the dates shown. There were no margin deposit liabilities at these dates.

	December 31, 2014	December 31, 2013
(in millions)		
Margin deposit assets	$ 9.1	$ 5.2

Offsetting of derivative assets and liabilities

We believe that entering into master trading and netting agreements mitigates the level of financial loss that could result from a default under derivatives agreements by allowing net settlement of derivative assets and liabilities. We generally enter into the following master trading and netting agreements: (1) the International Swaps and Derivatives Association Agreement, a standardized financial natural gas and electric contract; and (2) the North American Energy Standards Board Inc. Agreement, a standardized contract for the purchase and sale of natural gas. These master trading and netting agreements allow the counterparties to net settle sale and purchase transactions. Collateral requirements are calculated at the master trading and netting agreement level by the counterparty.

As shown above, our asset and liability commodity contract derivatives are reported at gross on the balance sheet. ASC guidance permits companies to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a liability) against fair value amounts recognized for derivative instruments that are executed with the same counterparty under the same master netting arrangement. For the years ended December 31, 2014 and December 31, 2013, we did not hold any collateral posted by our counterparties. The only collateral we have posted is our margin deposit assets described above. We have elected not to offset our margin deposit assets against any of our eligible commodity contracts.

15. FAIR VALUE MEASUREMENTS

The accounting guidance on fair value measurements establishes a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value. These tiers include: (i) Level 1, defined as quoted prices in active markets for identical instruments; (ii) Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and (iii) Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions. Our Level 2 fair value measurements consist of both quoted price inputs and inputs that are derived principally from or corroborated by observable market data.

The guidance also requires that the fair value measurement of assets and liabilities reflect the non-performance risk of counterparties and the reporting entity, as applicable. Therefore, using credit default spreads, we factored the impact of our own credit standing and the credit standing of our counterparties, as well as any potential credit enhancements (e.g. collateral) into the consideration of non-performance risk for both derivative assets and liabilities. The results of this analysis were not material to the financial statements.

Our Transmission congestion rights positions (TCR), which are acquired on the SPP Integrated Marketplace, are valued using the most recent monthly auction clearing prices. Our commodity contracts are valued using the market value approach on a recurring basis. The following fair value hierarchy table presents information about our TCR and commodity contracts measured at fair value as of December 31, 2013:

($ in 000's)		Fair Value Measurements at Reporting Date Using		
Description	**Assets/(Liabilities) at Fair Value**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
		December 31, 2014		
Derivative assets	$ 3,901	$ 1	$ 3,900	$ -
Derivative liabilities	$(9,712)	$ (9,712)	$ -	$ -
		December 31, 2013		
Derivative assets	$ 2,510	$ 543	$ 1,967	-
Derivative liabilities	$(4,688)	$ (4,688)	$ -	-

*The only recurring measurements are derivative related.

<u>Other fair value considerations</u>

Our cash and cash equivalents approximate fair value because of the short-term nature of these instruments, and are classified as Level 1 in the fair value hierarchy. The carrying amount of our short-term debt, which is composed of Empire issued commercial paper or revolving credit borrowings, also approximates fair value because of their short-term nature. These instruments are classified as Level 2 in the fair value hierarchy as they are valued based on market rates for similar market transactions.

The carrying amount of our total long-term debt exclusive of capital leases at December 31, 2014 and 2013 was $799 million and $739 million, compared to a fair market value of approximately $829 million and $715 million, respectively. These estimates were based on a bond pricing model, utilizing inputs classified as Level 2 in the fair value hierarchy, which include the quoted market prices for the same or similar issues or on the current rates offered to us for debt of the same remaining maturities. The estimated fair market value may not represent the actual value that could have been realized as of December 31, 2014 or that will be realizable in the future.

16. REGULATED OPERATING EXPENSE

The following table sets forth the major components comprising "regulated operating expenses" under "Operating Revenue Deductions" on our consolidated statements of income for the years ended (in thousands):

	December 31, 2014	2013	2012
Power operation expense (other than fuel)	$ 16,089	$ 15,643	$ 15,045
Electric transmission and distribution expense	27,919	21,863	17,083
Natural gas transmission and distribution expense	2,362	2,498	2,443
Customer accounts & assistance expense	11,239	11,180	10,211
Employee pension expense [1]	10,590	10,736	10,180
Employee healthcare plan [1]	9,147	10,190	9,825
General office supplies and expense	15,024	12,850	10,776
Administrative and general expense	14,385	14,800	15,091
Bad debt expense	3,420	3,665	3,038
Regulatory reversal of gain on sale of assets	44	1,236	-
Miscellaneous expense	472	672	679
TOTAL	$ 110,691	$ 105,333	$ 94,371

(1) Does not include the capitalized portion of actuarially calculated costs, but reflects the GAAP expensed portion of these costs plus or minus costs deferred to a regulatory asset or recognized as a regulatory liability for Missouri and Kansas jurisdictions.

THE EMPIRE DISTRICT ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

	Three Months Ended September 30	
	2015	**2014**
	(000's except per share amounts)	
Operating revenues:		
Electric	$ 162,412	$ 164,500
Gas	5,084	4,989
Other	2,218	2,023
	169,714	171,512
Operating revenue deductions:		
Fuel and purchased power	45,795	56,574
Cost of natural gas sold and transported	1,301	1,208
Regulated operating expenses	28,437	27,773
Other operating expenses	879	746
Maintenance and repairs	11,454	12,004
Depreciation and amortization	20,090	18,550
Provision for income taxes	15,850	13,819
Other taxes	10,125	9,129
	133,931	139,803
Operating income	35,783	31,709
Other income and (deductions):		
Allowance for equity funds used during construction	1,257	1,799
Interest income	2	4
Benefit for other income taxes	586	105
Other – non-operating expense, net	(1,751)	(313)
	94	1,595
Interest charges:		
Long-term debt	11,001	10,105
Short-term debt	80	46
Allowance for borrowed funds used during construction	(743)	(972)
Other	254	233
	10,592	9,412
Net income	**$ 25,285**	**$ 23,892**
Weighted average number of common shares outstanding - basic	43,728	43,367
Weighted average number of common shares outstanding - diluted	43,819	43,413
Total earnings per weighted average share of common stock – basic and diluted	**$ 0.58**	**$ 0.55**
Dividends declared per share of common stock	**$ 0.26**	**$ 0.255**

See accompanying Notes to Consolidated Financial Statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

	Nine Months Ended September 30,	
	2015	2014
	(000's except per share amounts)	
Operating revenues:		
Electric	$ 431,335	$ 458,355
Gas	31,181	36,587
Other	6,299	6,025
	468,815	500,967
Operating revenue deductions:		
Fuel and purchased power	133,926	166,518
Cost of natural gas sold and transported	14,765	18,931
Regulated operating expenses	84,656	83,339
Other operating expenses	2,474	2,243
Maintenance and repairs	37,303	33,654
Depreciation and amortization	60,237	54,648
Provision for income taxes	28,789	32,687
Other taxes	30,121	28,249
	392,271	420,269
Operating income	76,544	80,698
Other income and (deductions):		
Allowance for equity funds used during construction	3,469	4,573
Interest income	142	48
Benefit for other income taxes	713	203
Other – non-operating expense, net	(2,675)	(958)
	1,649	3,866
Interest charges:		
Long-term debt	32,504	30,316
Short-term debt	247	63
Allowance for borrowed funds used during construction	(2,030)	(2,542)
Other	780	736
	31,501	28,573
Net income	**$ 46,692**	**$ 55,991**
Weighted average number of common shares outstanding - basic	43,629	43,239
Weighted average number of common shares outstanding - diluted	43,721	43,272
Total earnings per weighted average share of common stock – basic and diluted	**$ 1.07**	**$ 1.29**
Dividends declared per share of common stock	**$ 0.78**	**$ 0.765**

See accompanying Notes to Consolidated Financial Statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

	Twelve Months Ended September 30, 2015	Twelve Months Ended September 30, 2014
	(000's except per share amounts)	
Operating revenues:		
Electric	$ 565,471	$ 588,611
Gas	46,437	53,406
Other	8,271	8,008
	620,179	650,025
Operating revenue deductions:		
Fuel and purchased power	182,494	209,745
Cost of natural gas sold and transported	22,860	28,496
Regulated operating expenses	112,094	108,788
Other operating expenses	3,217	2,915
Maintenance and repairs	50,424	44,763
Depreciation and amortization	78,774	72,483
Provision for income taxes	35,500	41,460
Other taxes	38,971	36,878
	524,334	545,528
Operating income	95,845	104,497
Other income and (deductions):		
Allowance for equity funds used during construction	5,317	5,905
Interest income	145	92
Benefit for other income taxes	687	164
Other – non-operating expense, net	(3,019)	(1,263)
	3,130	4,898
Interest charges:		
Long-term debt	42,824	40,427
Short-term debt	298	64
Allowance for borrowed funds used during construction	(2,984)	(3,246)
Other	1,033	996
	41,171	38,241
Net income	**$ 57,804**	**$ 71,154**
Weighted average number of common shares outstanding – basic	43,583	43,173
Weighted average number of common shares outstanding – diluted	43,677	43,202
Total earnings per weighted average share of common stock – basic	**$ 1.33**	**$ 1.65**
Total earnings per weighted average share of common stock – diluted	**$ 1.32**	**$ 1.65**
Dividends declared per share of common stock	**$ 1.04**	**$ 1.02**

See accompanying Notes to Consolidated Financial Statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS (UNAUDITED)

	September 30, 2015	December 31, 2014
	($-000's)	
Assets		
Plant and property, at original cost:		
Electric	$ 2,452,856	$ 2,420,824
Gas	82,363	79,364
Other	41,757	41,394
Construction work in progress	184,640	112,097
	2,761,616	2,653,679
Accumulated depreciation and amortization	753,309	743,407
	2,008,307	1,910,272
Current assets:		
Cash and cash equivalents	1,860	2,105
Restricted cash	4,726	4,726
Accounts receivable – trade, net of allowance $873 and $1,021, respectively	51,239	45,444
Accrued unbilled revenues	16,336	25,945
Accounts receivable – other	25,681	41,256
Fuel, materials and supplies	60,295	57,799
Prepaid expenses and other	31,220	27,879
Unrealized gain in fair value of derivative contracts	2,135	3,901
Regulatory assets	7,306	10,752
	200,798	219,807
Noncurrent assets and deferred charges:		
Regulatory assets	202,139	209,717
Goodwill	39,492	39,492
Unamortized debt issuance costs	8,829	8,821
Other	3,278	2,147
	253,738	260,177
Total Assets	$ 2,462,843	$ 2,390,256

(Continued)

See accompanying Notes to Consolidated Financial Statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY
CONSOLIDATED BALANCE SHEETS (UNAUDITED) (Continued)

	September 30, 2015	December 31, 2014
	($-000's)	
Capitalization and Liabilities		
Common stock, $1 par value, 43,760,441 and 43,479,186 shares issued and outstanding, respectively	$ 43,760	$ 43,479
Capital in excess of par value	655,777	649,543
Retained earnings	102,926	90,276
Total common stockholders' equity	802,463	783,298
Long-term debt (net of current portion):		
Obligations under capital lease	3,646	3,875
First mortgage bonds and secured debt	757,643	697,615
Unsecured debt	101,710	101,699
Total long-term debt	862,999	803,189
Total long-term debt and common stockholders' equity	1,665,462	1,586,487
Current liabilities:		
Accounts payable and accrued liabilities	54,337	83,420
Current maturities of long-term debt	304	292
Short-term debt	16,250	44,000
Regulatory liabilities	6,356	7,898
Customer deposits	14,271	13,747
Interest accrued	15,159	6,565
Unrealized loss in fair value of derivative contracts	4,371	6,469
Taxes accrued	19,719	3,380
Other current liabilities	513	356
	131,280	166,127
Commitments and contingencies (Note 7)		
Noncurrent liabilities and deferred credits:		
Regulatory liabilities	136,165	128,471
Deferred income taxes	409,134	377,452
Unamortized investment tax credits	18,260	18,367
Pension and other postretirement benefit obligations	74,739	93,863
Unrealized loss in fair value of derivative contracts	3,061	3,243
Other	24,742	16,246
	666,101	637,642
Total Capitalization and Liabilities	$ 2,462,843	$ 2,390,256

See accompanying Notes to Consolidated Financial Statements.

THE EMPIRE DISTRICT ELECTRIC COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
	($-000's)	
Operating activities:		
Net income	$ 46,692	$ 55,991
Adjustments to reconcile net income to cash flows from operating activities:		
Depreciation and amortization including regulatory items	67,099	61,326
Pension and other postretirement benefit costs, net of contributions	(12,038)	(1,354)
Deferred income taxes and unamortized investment tax credit, net	28,237	12,744
Allowance for equity funds used during construction	(3,469)	(4,573)
Stock compensation expense	1,507	2,608
Other	(45)	130
Non-cash (gain)/loss on derivatives	4,892	425
Cash flows impacted by changes in:		
Accounts receivable and accrued unbilled revenues	14,496	4,334
Fuel, materials and supplies	(2,495)	(5,690)
Prepaid expenses, other current assets and deferred charges	(5,813)	(4,833)
Accounts payable and accrued liabilities	(24,621)	(20,237)
Asset retirement obligations	(27)	(1,232)
Interest, taxes accrued and customer deposits	25,457	24,571
Other liabilities and other deferred credits	5,818	(1,834)
Net cash provided by operating activities	145,690	122,376
Investing activities:		
Capital expenditures – regulated	(145,886)	(149,778)
Capital expenditures and other investments – non-regulated	(1,828)	(1,140)
Restricted cash	-	(4,854)
Net cash used in investing activities	(147,714)	(155,772)
Financing activities:		
Proceeds from first mortgage bonds, net	60,000	-
Long-term debt issuance costs	(519)	-
Proceeds from issuance of common stock, net of issuance costs	4,307	6,465
Net short-term debt borrowings/(repayments)	(27,750)	59,000
Dividends	(34,042)	(33,085)
Other	(217)	(205)
Net cash provided by financing activities	1,779	32,175
Net increase (decrease) in cash and cash equivalents	(245)	(1,221)
Cash and cash equivalents at beginning of period	2,105	3,475
Cash and cash equivalents at end of period	$ 1,860	$ 2,254

See accompanying Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Note 1 - Summary of Significant Accounting Policies

We operate our businesses as three segments: electric, gas and other. The Empire District Electric Company (EDE), a Kansas corporation organized in 1909, is an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. As part of our electric segment, we also provide water service to three towns in Missouri. The Empire District Gas Company (EDG) is our wholly-owned subsidiary which provides natural gas distribution to customers in 48 communities in northwest, north central and west central Missouri. Our other segment consists of our fiber optics business.

The accompanying interim financial statements do not include all disclosures included in the annual financial statements and therefore should be read in conjunction with the financial statements and notes thereto included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2014.

The information furnished reflects all adjustments, consisting only of normal recurring adjustments, which are in our opinion necessary to state fairly the results for the interim periods as well as present these periods on a consistent basis with the financial statements for the fiscal year ended December 31, 2014.

Note 2 - Recently Issued and Proposed Accounting Standards

Revenue from contracts with customers: In June 2014, the FASB issued new guidance governing revenue recognition. Under the new guidance, an entity is required to recognize revenue in a pattern that depicts the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In July 2015, the FASB approved a one year delay in the standard's effective date. The new standard is now effective for interim and annual reporting periods beginning after December 15, 2017. We are evaluating the impact of the adoption of this standard.

Extraordinary and unusual items: In January 2015, the FASB issued revised guidance that eliminates from GAAP the concept of extraordinary items. Under the revised guidance, an entity will no longer be required to separately classify, present and disclose events or transactions that are determined to be both unusual in nature and infrequent in occurrence. The revised guidance is effective for interim and annual reporting periods beginning after December 15, 2015. The application of this standard is not expected to have a material impact on our results of operations, financial position or liquidity.

Presentation of debt issuance costs: In April 2015, the FASB issued revised guidance addressing the presentation requirements for debt issuance costs. Under the revised guidance, all costs incurred to issue debt are to be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability. The revised guidance is effective for interim and annual reporting periods beginning after December 15, 2015. As of September 30, 2015, we expect that the implementation of this standard would reduce both assets and liabilities by approximately $8.8 million. The application of this standard is not expected to have a material impact on our results of operations or liquidity.

See Note 1 under "Notes to Consolidated Financial Statements" in our Annual Report on Form 10-K for the year ended December 31, 2014 for further information regarding recently issued and proposed accounting standards.

Note 3– Regulatory Matters

The following table sets forth the components of our regulatory assets and liabilities on our consolidated balance sheet (in thousands).

	Regulatory Assets and Liabilities	
	September 30, 2015	December 31, 2014
Regulatory Assets:		
Current:		
Under recovered fuel costs	$ 159	$ 2,618
Current portion of long-term regulatory assets	7,147	8,134
Regulatory assets, current	7,306	10,752
Long-term:		
Pension and other postretirement benefits(1)	102,844	111,121
Income taxes	48,253	47,177
Deferred construction accounting costs(2)	15,114	15,521
Unamortized loss on reacquired debt	9,900	10,405
Unsettled derivative losses – electric segment	6,564	9,037
System reliability – vegetation management	3,863	5,337
Storm costs(3)	3,672	4,183
Asset retirement obligation	6,800	5,145
Customer programs(4)	5,820	5,253
Missouri solar initiative(5)	1,719	-
Under recovered fuel costs	1,744	951
Current portion of long-term regulatory assets	(7,147)	(8,134)
Other	2,993	3,721
Regulatory assets, long-term	202,139	209,717
Total Regulatory Assets	$ 209,445	$ 220,469

	September 30, 2015	December 31, 2014
Regulatory Liabilities:		
Current:		
Over recovered fuel costs	$ 2,934	$ 4,227
Current portion of long-term regulatory liabilities	3,422	3,671
Regulatory liabilities, current	6,356	7,898
Long-term:		
Costs of removal	94,503	90,527
SWPA payment for Ozark Beach lost generation	14,793	16,744
Income taxes	11,291	11,451
Deferred construction accounting costs – fuel(6)	7,730	7,849
Unamortized gain on interest rate derivative	3,074	3,201
Pension and other postretirement benefits	1,364	2,369
Over recovered fuel costs	5,512	1
Current portion of long-term regulatory liabilities	(3,422)	(3,671)
System reliability – vegetation management	1,320	-
Regulatory liabilities, long-term	136,165	128,471
Total Regulatory Liabilities	$ 142,521	$ 136,369

(1) Primarily consists of unfunded pension and other postretirement benefits (OPEB) liability. See Note 8.
(2) Reflects deferrals resulting from 2005 regulatory plan relating to Iatan 1, Iatan 2 and Plum Point. These amounts are being recovered over the life of the plants.
(3) Reflects ice storm costs incurred in 2007 and costs incurred as a result of the May 2011 tornado including an accrued carrying charge and deferred depreciation totaling $3.0 million at September 30, 2015.
(4) Primarily consists of Missouri energy efficiency programs.
(5) Resulting from the Missouri Clean Energy Initiative and consists of approximately 109 solar rebate applications processed and internal costs as of September 30, 2015, resulting in solar rebate-related costs totaling approximately $1.6 million.
(6) Resulting from regulatory plan requiring deferral of the fuel and purchased power impacts of Iatan 2.

Note 4– Risk Management and Derivative Financial Instruments

We engage in hedging activities in an effort to minimize our risk from the volatility of natural gas prices and power cost risk associated with exposure to congestion costs. We enter into both physical forward and financial derivative contracts with counterparties relating to our future natural gas requirements that lock in prices (with respect to a range of predetermined percentages of our expected future natural gas needs) in an attempt to lessen the volatility in our fuel expenditures and gain cost predictability.

We began acquiring Transmission Congestion Rights (TCR) in 2013 in an attempt to mitigate the cost of power we purchase from the Southwest Power Pool (SPP) Integrated Marketplace (IM) due to congestion exposure. TCRs entitle the holder to a stream of revenues (or charges) based on the day-ahead congestion on the transmission path. TCRs can be purchased or self-converted using rights allocated based on prior investments made in the transmission system. If risk is not timely and adequately balanced or if counterparties fail to perform contractual obligations, actual results could differ materially from intended results.

All derivative instruments are recognized at fair value on the balance sheet. The unrealized losses or gains from derivatives used to hedge our fuel and purchased power costs in our electric segment are recorded in regulatory assets or liabilities. All gains and losses from derivatives related to the gas segment are also recorded in regulatory assets or liabilities. This is in accordance with the Accounting Standards Codification (ASC) guidance on regulated operations, given that those gains or losses are probable of refund or recovery, respectively, through our fuel adjustment mechanisms.

Risks and uncertainties affecting the determination of fair value include: market conditions in the energy industry, especially the effects of price volatility, regulatory and global political environments and requirements, fair value estimations on longer term contracts, the effectiveness of the derivative instruments in hedging the change in fair value of the hedged item, estimating underlying fuel demand and counterparty ability to perform. If we estimate that we have overhedged forecasted demand, the gain or loss on the overhedged portion will be recognized immediately as fuel and purchased power expense in our Consolidated Statement of Income and subject to our fuel adjustment mechanism.

As of September 30, 2015 and December 31, 2014, we have recorded the following assets and liabilities representing the fair value of derivative financial instruments, (in thousands):

ASSET DERIVATIVES		September 30, 2015	December 31, 2014
Hedging instruments	Balance Sheet Classification	Fair Value	Fair Value
Natural gas contracts, gas segment	Current assets	$ 5	$ -
	Non-current other assets	17	-
Natural gas contracts, electric segment	Current assets	-	1
Transmission congestion rights, electric segment	Current assets	2,130	3,900
Total derivatives assets		**$ 2,152**	**$ 3,901**

LIABILITY DERIVATIVES		September 30, 2015	December 31, 2014
Hedging instruments	Balance Sheet Classification	Fair Value	Fair Value
Natural gas contracts, gas segment	Current liabilities	$ 219	$ 476
	Non-current liabilities and deferred credits	22	
Natural gas contracts, electric segment	Current liabilities	4,152	5,993
	Non-current liabilities and deferred credits	3,039	3,243
Total derivatives liabilities		**$ 7,432**	**$ 9,712**

Electric Segment

At September 30, 2015, approximately $4.2 million of unrealized net losses are applicable to natural gas financial instruments which will settle within the next twelve months.

The following tables set forth “mark-to-market” pre-tax gains/(losses) from non-designated derivative instruments for the electric segment for each of the periods ended September 30, (in thousands):

Non-Designated Hedging Instruments - Due to Regulatory Accounting Electric Segment	Balance Sheet Classification of Gain / (Loss) on Derivative	Amount of Gain / (Loss) Recognized on Balance Sheet					
		Three Months Ended		Nine Months Ended		Twelve Months Ended	
		2015	2014	2015	2014	2015	2014
Commodity contracts	Regulatory (assets)/liabilities	$ (1,690)	$ (2,695)	$ (3,909)	$ (537)	$(10,152)	$ 903
Transmission congestion rights	Regulatory (assets)/liabilities	125	(267)	4,750	11,385	6,322	13,352
Total Electric Segment		**$ (1,565)**	**$ (2,962)**	**$ 841**	**$10,848**	**$ (3,830)**	**$14,255**

Non-Designated Hedging Instruments - Due to Regulatory Accounting Electric Segment	Statement of Income Classification of Gain / (Loss) on Derivative	Amount of Gain / (Loss) Recognized in Income on Derivative					
		Three Months Ended		Nine Months Ended		Twelve Months Ended	
		2015	2014	2015	2014	2015	2014
Commodity contracts	Fuel and purchased power expense	$ (4,104)	$ (1,849)	$ (6,381)	$ (934)	$ (7,105)	$ (1,187)
Transmission congestion rights	Fuel and purchased power expense	1,133	3,677	6,446	8,899	8,653	8,980
Total Electric Segment		**$(2,971)**	**$ 1,828**	**$ 65**	**$7,965**	**$ 1,548**	**$ 7,793**

We also enter into fixed-price forward physical contracts for the purchase of natural gas, coal and purchased power. These contracts are not subject to fair value accounting because they qualify for the normal purchase normal sale exemption. We have a process in place to determine if any future executed contracts that otherwise qualify for the normal purchase normal sale exemption contain a price adjustment feature and will account for these contracts accordingly.

As of September 30, 2015, the following volumes and percentage of our anticipated volume of natural gas usage for our electric operations for the remainder of 2015 and for the next four years are shown below at the following average prices per Dekatherm (Dth). We utilize the following procurement guidelines for our electric segment, allowing the flexibility to hedge up to 100% of the current year's and 80% of any future year's expected requirements while being cognizant of volume risk. The 80% guideline is an annual target and volumes up to 100% can be hedged in any given month. For years beyond year four, additional factors of long term uncertainty (including with respect to required volumes and counterparty credit) are also considered.

		Dth Hedged			Procurement
Year	% Hedged	Physical	Financial	Average Price	Guidelines
Remainder 2015	47%	-	600,000	$ 4.486	Up to 100%
2016	54%	2,676,000	2,580,000	$ 3.795	60%
2017	20%	782,900	1,300,000	$ 4.133	40%
2018	10%	565,000	500,000	$ 4.121	20%
2019	0%	-	-	$ -	10%

At September 30, 2015, the following transmission congestion rights (TCR) have been obtained to hedge congestion risk in the SPP IM (dollars in thousands):

Year	Monthly MWH Hedged	Estimated Fair Value
2015	2,608	$ 2,130

Gas Segment

We attempt to mitigate our natural gas price risk for our gas segment by a combination of (1) injecting natural gas into storage during the off-heating season months, (2) purchasing physical forward contracts and (3) purchasing financial derivative contracts. We target to have 95% of our storage capacity full by November 1 for the upcoming winter heating season. As the winter progresses, gas is withdrawn from storage to serve our customers. As of September 30, 2015, we had 1.6 million Dths in storage on the three pipelines that serve our customers. This represents 79% of our storage capacity.

The following table sets forth our long-term hedge strategy of mitigating price volatility for our customers by hedging a minimum of expected gas usage for the current winter season and the next two winter seasons by the beginning of the Actual Cost Adjustment (ACA) year at September 1 and illustrates our hedged position as of September 30, 2015 (Dth in thousands).

Season	Minimum % Hedged*	Dth Hedged Financial	Dth Hedged Physical	Dth in Storage	Actual % Hedged
Current	50%	780,000	-	1,617,261	74%
Second	Up to 50%	100,000	-	-	3%
Third	Up to 20%	140,000	-	-	4%

**Procurement guidelines*

A Purchased Gas Adjustment (PGA) clause is included in our rates for our gas segment operations. Therefore, we mark to market any unrealized gains or losses and any realized gains or losses relating to financial derivative contracts to a regulatory asset or regulatory liability account on our balance sheet.

The following table sets forth "mark-to-market" pre-tax gains / (losses) from derivatives not designated as hedging instruments for the gas segment for each of the periods ended September 30, (in thousands).

Non-Designated Hedging Instruments Due to Regulatory Accounting - Gas Segment	Balance Sheet Classification of Gain / (Loss) on Derivative	Amount of Gain/(Loss) Recognized on Balance Sheet					
		Three Months Ended		Nine Months Ended		Twelve Months Ended	
		2015	2014	2015	2014	2015	2014
Commodity contracts	Regulatory (assets)/ liabilities	$ (236)	$ (23)	$ (50)	$ 86	$ (647)	$ 141
Total - Gas Segment		**$ (236)**	**$ (23)**	**$ (50)**	**$ 86**	**$ (647)**	**$ 141**

Contingent Features

Certain of our derivative instruments contain provisions that are triggered if we fail to maintain an investment grade credit rating with any relevant credit rating agency. If our debt were to fall below investment grade, the counterparties to the derivative instruments could request increased collateralization on derivative instruments in net liability positions. We had no derivative instruments with the credit-risk-related contingent features in a net liability position on September 30, 2015 and have posted no collateral with counterparties in the normal course of business. Amounts reported as margin deposit assets represent our funds held on deposit for our contracts held with our NYMEX broker and other financial contracts with other counterparties that resulted from us exceeding agreed-upon credit limits established by the counterparties. The following table depicts our margin deposit assets at the dates shown. There were no margin deposit liabilities at these dates.

(in millions)	September 30, 2015	December 31, 2014
Margin deposit assets	$ 7.6	$ 9.1

Offsetting of derivative assets and liabilities

We believe that entering into master trading and netting agreements mitigates the level of financial loss that could result from a default under derivatives agreements by allowing net settlement of derivative assets and liabilities. We generally enter into the following master trading and netting agreements: (1) the International Swaps and Derivatives Association Agreement, a standardized financial natural gas and electric contract; and (2) the North American Energy Standards Board Inc. Agreement, a standardized contract for the purchase and sale of natural gas. These master trading and netting agreements allow the counterparties to net settle sale and purchase transactions. Collateral requirements are calculated at the master trading and netting agreement level by the counterparty.

As shown above, our asset and liability commodity contract derivatives are reported at gross on the balance sheet. ASC guidance permits companies to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a liability) against fair value amounts recognized for derivative instruments that are executed with the same counterparty under the same master netting arrangement. For the periods ended September 30, 2015 and December 31, 2014, we did not hold any collateral posted by our counterparties. The only collateral we have posted is our margin deposit assets described above. We have elected not to offset our margin deposit assets against any of our eligible commodity contracts.

Note 5– Fair Value Measurements

The accounting guidance on fair value measurements establishes a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value. These tiers include: (i) Level 1, defined as quoted prices in active markets for identical instruments; (ii) Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and (iii) Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions. Our Level 2 fair value measurements consist of both quoted price inputs and inputs that are derived principally from or corroborated by observable market data.

The guidance also requires that the fair value measurements of assets and liabilities reflect the nonperformance risk of counterparties and the reporting entity, as applicable. Therefore, using credit default spreads, we factored the impact of our own credit standing and the credit standing of our counterparties, as well as any potential credit enhancements (e.g. collateral) into the consideration of nonperformance risk for both derivative assets and liabilities. The results of this analysis were not material to the financial statements.

Our TCR positions, which are acquired on the SPP IM, are valued using the most recent monthly auction clearing prices. Our commodity contracts are valued using the market value approach on a recurring basis. The following fair value hierarchy table presents information about our TCR and commodity contracts measured at fair value as of September 30, 2015 and December 31, 2014.

($ in 000's)		Fair Value Measurements at Reporting Date Using		
Description	**Assets/(Liabilities) at Fair Value**	**Quoted Prices in Active Markets for Identical Assets/(Liabilities) (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
		September 30, 2015		
Derivative assets	$ 2,152	$ 22	$ 2,130	$ -
Derivative liabilities	$ (7,432)	$ (7,432)	$ -	$ -
		December 31, 2014		
Derivative assets	$ 3,901	$ 1	$ 3,900	$ -
Derivative liabilities	$ (9,712)	$ (9,712)	$ -	$ -

**The only recurring measurements are derivative related.*

Other fair value considerations

Our cash and cash equivalents approximate fair value because of the short-term nature of these instruments, and are classified as Level 1 in the fair value hierarchy. The carrying amount of our short-term debt, which is composed of Empire issued commercial paper or revolving credit borrowings, also approximates fair value because of their short-term nature. These instruments are classified as Level 2 in the fair value hierarchy as they are valued based on market rates for similar market transactions.

The carrying amount of our total long-term debt exclusive of capital leases at September 30, 2015 was $859 million and at December 31, 2014 was $799 million. The fair market value at September 30, 2015 was approximately $827 million as compared to approximately $829 million at December 31, 2014. These estimates were based on a bond pricing model, utilizing inputs classified as Level 2 in the fair value hierarchy, which include the quoted market prices for the same or similar issues or on the current rates offered to us for debt of the same remaining maturities. The estimated fair market value may not represent the actual value that could have been realized as of September 30, 2015 or that will be realizable in the future.

Note 6– Financing

On June 11, 2015, we entered into a Bond Purchase Agreement for a private placement of $60.0 million of 3.59% First Mortgage Bonds due 2030. A delayed settlement occurred on August 20, 2015. Interest is payable semi-annually on the bonds on each February 20 and August 20, commencing February 20, 2016. The bonds are prepayable at our option at any time prior to maturity, at par plus a make whole premium, together with accrued and unpaid interest, if any, to the prepayment date. The proceeds from the sale of the bonds were used to refinance existing short-term indebtedness and for general corporate purposes. The bonds have not been and will not be registered under the Securities Act of 1933, as amended. The bonds were issued under the Indenture of Mortgage and Deed of Trust of the Empire District Electric Company (EDE Mortgage). The principal amount of all series of first mortgage bonds outstanding at any one time under the EDE Mortgage is limited by terms of the mortgage to $1 billion. Substantially all of the property, plant and equipment of The Empire District Electric Company (but not its subsidiaries) is subject to the lien of the EDE Mortgage.

We have an unsecured revolving credit facility of $200 million in place through October 20, 2019. This agreement may be used for working capital, commercial paper back-up and general corporate purposes. The credit facility includes a $20 million swingline loan sublimit, a $20 million sublimit for letters of credit issuance and, subject to bank approval, a $75 million accordion feature and two one-year extensions of the credit facility's maturity date.

The credit facility requires our total indebtedness to be less than 65.0% of our total capitalization at the end of each fiscal quarter and a failure to maintain this ratio will result in an event of default under the credit facility and will prohibit us from borrowing funds thereunder. As of September 30, 2015, we were in compliance with this covenant as our ratio of total indebtedness was 52% of our total capitalization. This credit facility is also subject to cross-default if we default on more than $25 million in the aggregate on our other indebtedness. As of September 30, 2015, we were not in default under any of such other indebtedness.

The credit agreement does not legally restrict the use of our cash in the normal course of operations. There were no outstanding borrowings under the agreement at September 30, 2015; however, $16.3 million was used to back up our outstanding commercial paper.

Note 7– Commitments and Contingencies

Legal Proceedings

We are a party to various claims and legal proceedings arising out of the normal course of our business. We regularly analyze this information, and provide accruals for any liabilities, in accordance with the guidelines presented in the ASC on accounting for contingencies. In the opinion of management, it is not probable, given the company's defenses, that the ultimate outcome of these claims and lawsuits will have a material adverse effect upon our financial condition, or results of operations or cash flows.

Coal, Natural Gas and Transportation Contracts

The following table sets forth our firm physical gas, coal and transportation contracts for the periods indicated as of September 30, 2015 (in millions).

	Firm physical gas and transportation contracts	Coal and coal transportation contracts
October 1, 2015 through December 31, 2015	$ 6.1	$ 4.9
January 1, 2016 through December 31, 2017	45.9	29.8
January 1, 2018 through December 31, 2019	33.6	21.4
January 1, 2020 and beyond	49.6	-

We have entered into long and short-term agreements to purchase coal and natural gas for our energy supply and natural gas operations. Under these contracts, the natural gas supplies are divided into firm physical commitments and derivatives that are used to hedge future purchases. In the event that this gas cannot be used at our plants, the gas would be placed in storage. The firm physical gas and transportation commitments are detailed in the table above.

We have coal supply agreements and transportation contracts in place to provide for the delivery of coal to the plants. These contracts are written with Force Majeure clauses that enable us to reduce tonnages or cease shipments under certain circumstances or events. These include mechanical or electrical maintenance items, acts of God, war or insurrection, strikes, weather and other disrupting events. This reduces the risk we have for not taking the minimum requirements of fuel under the contracts. The minimum requirements for our coal and coal transportation contracts as of September 30, 2015, are detailed in the table above.

Purchased Power

We have three purchased power agreements.

The Plum Point Energy Station (Plum Point) is a 670-megawatt, coal-fired generating facility near Osceola, Arkansas. We own, through an undivided interest, 50 megawatts of the unit's capacity. We also have a long-term (30 year) agreement for the purchase of an additional 50 megawatts of capacity from Plum Point. Commitments under this agreement are approximately $280.1 million through August 31, 2039, the end date of the agreement. We had the option to purchase an undivided ownership interest in the 50 megawatts covered by the purchased power agreement. We evaluated this purchase option as part of our Integrated Resource Plan (IRP), which was filed with the MPSC on July 1, 2013. We did not exercise this option by the March 2015 notification deadline in the contract.

We have a 20-year purchased power agreement, which began on December 15, 2008, with Cloud County Windfarm, LLC, owned by EDP Renewables North America LLC, Houston, Texas to purchase the energy generated at the approximately 105-megawatt Phase 1 Meridian Way Wind Farm located in Cloud County, Kansas. Annual payments are contingent upon output of the facility and can range from zero to a maximum of approximately $14.6 million based on a 20-year average cost.

We also have a 20-year purchased power agreement, which began on December 15, 2005, with Elk River Windfarm, LLC, owned by IBERDROLA RENEWABLES, Inc., to purchase the energy generated at the 150-megawatt Elk River Windfarm located in Butler County, Kansas. Annual payments are contingent upon output of the facility and can range from zero to a maximum of approximately $16.9 million based on a 20-year average cost.

We do not own any portion of these windfarms. Payments for these agreements are recorded as purchased power expenses, and, because of the contingent nature of these payments, are not included in our operating lease obligations.

New Construction

We have in place a contract with a third party vendor to complete engineering, procurement, and construction activities at our Riverton plant to convert Riverton Unit 12 from a simple cycle combustion turbine to a combined cycle unit. The conversion includes the installation of a heat recovery steam generator (HRSG), steam turbine generator, auxiliary boiler, cooling tower, and other auxiliary equipment. The Air Emission Source Construction Permit necessary for this project was issued by Kansas Department of Health and Environment on July 11, 2013. This conversion is currently scheduled to be completed in early to mid-2016 at a cost estimated to range from $165 million to $175 million, excluding allowance for funds used during construction (AFUDC). Construction costs, consisting of pre-engineering, site preparation activities and contract costs incurred project to date through September 30, 2015 were $150 million, excluding AFUDC. The remaining amount is included in our five-year capital expenditure plan.

See "Environmental Matters" below for more information.

Leases

We have purchased power agreements with Cloud County Windfarm, LLC and Elk River Windfarm, LLC, which are considered operating leases for GAAP purposes. Details of these agreements are disclosed in the Purchased Power section of this note.

We also currently have short-term operating leases for two unit trains to meet coal delivery demands, for garage and office facilities for our electric segment and for one office facility related to our gas segment. In addition, we have capital leases for certain office equipment and 108 railcars to provide coal delivery for our ownership and purchased power agreement shares of the Plum Point generating facility.

The gross amount of assets recorded under capital leases total $5.3 million at September 30, 2015.

Environmental Matters

We are subject to various federal, state, and local laws and regulations with respect to air and water quality and with respect to hazardous and toxic materials and hazardous and other wastes, including their identification, transportation, disposal, record-keeping and reporting, as well as remediation of contaminated sites and other environmental matters. We believe that our operations are in material compliance with present environmental laws and regulations. Environmental requirements have changed frequently and become more stringent over time. We expect this trend to continue. While we are not in a position to accurately estimate compliance costs for any new requirements, we expect these costs to be material, although recoverable in rates.

The Federal Clean Air Act (CAA) and comparable state laws regulate air emissions from stationary sources such as electric power plants through permitting and/or emission control and related requirements. These requirements include maximum emission limits on our facilities for sulfur dioxide (SO2), particulate matter, nitrogen oxides (NOx), carbon monoxide (CO), and hazardous air pollutants including mercury. In the future they will include limits on greenhouse gases (GHG) such as carbon dioxide (CO2).

Compliance Plan

In order to comply with current and forthcoming environmental regulations, we continue to implement our compliance plan and strategy (Compliance Plan). The Mercury Air Toxic Standards (MATS) and the Clean Air Interstate Rule (CAIR), replaced by the Cross State Air Pollution Rule (CSAPR), which we discuss further below, are the drivers behind our Compliance Plan and its implementation schedule. The MATS requires reductions in mercury, acid gases and other emissions considered hazardous air pollutants (HAPS). They became effective in April 2012 and required full compliance by April 16, 2015. We are currently in material compliance with MATS, although the regulation has been remanded to the D.C. Circuit Court for further consideration (discussed below). The CSAPR was first proposed by the Environmental Protection Agency (EPA) in July 2010 as a replacement of CAIR and came into effect on January 1, 2015. We anticipate compliance costs associated with the MATS, CAIR and CSAPR regulations to be recoverable in our rates.

Our Compliance Plan largely follows the preferred plan presented in our Integrated Resource Plan (IRP), filed in mid-2013 with the MPSC. In addition to the Riverton Unit 12 project discussed above, the process of installing a scrubber, fabric filter, and powder activated carbon injection system at our Asbury plant has been completed and the equipment placed in service in December 2014. This addition required the retirement of Asbury Unit 2, a steam turbine rated at 14 megawatts that was used for peaking purposes. Asbury Unit 2 was retired on December 31, 2013.

In September 2012, we completed the transition of our Riverton Units 7 and 8 from operation on coal and natural gas to operation solely on natural gas. Riverton Unit 7 was permanently removed from service on June 30, 2014. Riverton Unit 8 and Unit 9 (a small combustion turbine that required steam from Unit 8 for start-up) were retired June 30, 2015.

Air Emissions

The CAA regulates the amount of NOx and SO2 an affected unit can emit. As currently operated, each of our affected units is in compliance with the applicable NOx and SO2 limits. Beginning January 1, 2015, NOx emissions are regulated by CSAPR and National Ambient Air Quality Standards (NAAQS) rules for ozone. Beginning January 1, 2015, SO2 emissions are regulated by the Title IV Acid Rain Program and the CSAPR.

CAIR:

The CAIR generally called for fossil-fueled power plants greater than 25 megawatts to reduce emission levels of SO_2 and/or NO_x in 28 eastern states and the District of Columbia, including Missouri, where our Asbury, Energy Center, State Line and Iatan Units No. 1 and No. 2 are located. Kansas was not included in CAIR and our Riverton Plant was not affected. Arkansas, where our Plum Point Plant is located, was included for ozone season NO_x but not for SO_2. We were in full compliance with CAIR, which ended December 31, 2014.

CSAPR:

The CSAPR requires 23 states to reduce annual SO_2 and NO_x emissions to help downwind areas attain NAAQS for fine particulate matter. Twenty-five states are required to reduce ozone season NO_x emissions to help downwind states attain NAAQS for ozone. The CSAPR NO_x annual program impacts our Missouri and Kansas units while the CSAPR NO_x ozone season program impacts our units in Missouri plus our unit in Arkansas.

The CSAPR divides the states required to reduce SO_2 into two groups. Both groups must reduce their SO_2 emissions in Phase 1. Group 1 states, which include our sources in Missouri and Arkansas, must make additional SO_2 reductions for Phase 2 in order to eliminate their significant contribution to air quality problems in downwind areas. Empire's units in Kansas are in Group 2 of the CSAPR SO_2 program.

Under the CSAPR Program, in our most current five-year business plan (2015-2019), which assumes normal operations while maintaining compliance with permit conditions, we anticipate that it may be economically beneficial to purchase allowances for some of these pollutants if needed, but at the time of this writing the allowance markets have not been fully developed. We are currently in material compliance with CSAPR and expect that we will be able to meet all applicable, future CSAPR requirements.

Mercury Air Toxics Standard (MATS):

As described above, the MATS standard required compliance by April 2015. Following the completion of the Asbury Air Quality Control System (AQCS) project and the demonstration of continuous compliance as required by the regulation, we are in material compliance with MATS.

In June 2015, the U.S. Supreme Court remanded the MATS back to the D.C. Circuit Court, holding that the EPA must consider cost (including cost of compliance) before deciding whether regulation is appropriate and necessary. The court noted that it will be up to the EPA to decide within the limits of reasonable interpretation how to account for cost. MATS remains in effect until the D.C. Circuit Court acts. Accordingly, we and other entities subject to MATS must comply with its terms absent further relief granted.

National Ambient Air Quality Standards (NAAQS):

Under the CAA, the EPA sets NAAQS for certain emissions considered harmful to public health and the environment, including particulate matter (PM), NO_x, CO, SO_2, and ozone which result from fossil fuel combustion. Our facilities are currently in compliance with all applicable NAAQS.

In January 2013, the EPA finalized the revised PM 2.5 primary annual standard at 12 ug/m3 (micrograms per cubic meter of air). States are required to meet the primary standard in 2020. The standard should have no impact on our existing generating fleet because the regional ambient monitor results are below the PM 2.5 required level. However, the PM 2.5 standards could impact future major modifications/construction projects that require additional permits.

Ozone, also called ground level smog, is formed by the mixing of NO_x and Volatile Organic Compounds (VOCs) in the presence of sunlight. Based on the current standard, our service territory is designated as attainment, meaning that it is in compliance with the standard. A lower ozone NAAQS was finalized by the EPA on October 1, 2015. This revised Ozone NAAQS could affect our region and we will continue to evaluate the impact it would have on our generating plants.

Greenhouse Gases (GHGs):

EDE and EDG's GHG emissions have been reported to the EPA as required under the Mandatory GHG Reporting Rule each year since 2010.

A series of actions and decisions including the Tailoring Rule, which regulates carbon dioxide and other GHG emissions from certain stationary sources, have further set the foundation for the regulation of GHGs. However, because of the uncertainties regarding the final outcome of the GHG regulations (discussed below), the ultimate cost of compliance cannot be determined at this time. In any case, we expect the cost of complying with any such regulations to be recoverable in our rates.

In April 2012, the EPA proposed a Carbon Pollution Standard for new power plants to limit the amount of carbon emitted by Electric Generating Utilities (EGUs). This standard was rescinded, and a re-proposal of standards of performance for affected fossil fuel-fired EGUs was published in January 2014. The proposed rule applies only to new EGUs and sets separate standards for natural gas-fired combustion turbines and for fossil fuel-fired utility boilers. The proposal would not apply to existing units, including modifications such as those required to meet other air pollution standards which were recently completed at our Asbury facility and are currently being undertaken at the Riverton facility with the conversion of simple cycle Unit 12 to combined cycle.

On August 3, 2015, the EPA released the final rule for limiting carbon emissions from existing power plants. The "Clean Power Plan" requires a 32% carbon emission reduction from 2005 baseline levels by 2030 and requires fossil fuel-fired power plants across the nation, including those in Empire's fleet, to meet state-specific goals to lower carbon levels. States will choose between two plan types to meet their goals: an emission standards plan which includes source-specific requirements impacting affected power plants or a state measures plan which includes a mixture of measures implemented by the state.

By September 6, 2016, each state must either submit to the EPA its initial plan with a request for an extension or a final plan. If the state receives an extension, the final plan must be submitted by September 6, 2018. States will then implement plans to achieve the progressive CO2 emissions performance rates over the period of 2022 to 2029 with the final CO2 goal accountability by 2030. Empire continues to evaluate potential paths forward on the final rule released by the EPA.

Water Discharges

We operate under the Kansas and Missouri Water Pollution Plans pursuant to the Federal Clean Water Act (CWA). Our plants are in material compliance with applicable regulations and have received all necessary discharge permits.

The Riverton Units 7 and 8 and Iatan Unit 1, which utilize once-through cooling water, were affected by regulations for Cooling Water Intake Structures issued by the EPA under the CWA Section 316(b) Phase II. The EPA published the final rule on August 15, 2014 with an effective date of October 14, 2014. An industry coalition has filed an appeal of the rule in the Fifth Circuit and additional court challenges are expected. We expect the regulations to have a limited impact at Riverton given the retirement of Unit 8 on June 30, 2015. A new intake structure design and cooling tower will be constructed as part of the Unit 12 conversion at Riverton. Impacts at Iatan 1 could range from flow velocity reductions or traveling screen modifications for fish handling to installation of a closed cycle cooling tower retrofit. Iatan Unit 2 and Plum Point Unit 1 are covered by the regulation, but were constructed with cooling towers, the proposed Best Technology Available. We expect them to be unaffected or minimally affected by the final rule.

Surface Impoundments

We own and maintain a coal ash impoundment located at our Asbury Power Plant. Additionally, we own a 12% interest in a coal ash impoundment at the Iatan Generating Station and a 7.52% interest in a coal ash impoundment at Plum Point. As a result of the transition from coal to natural gas fuel for Riverton Units 7 and 8, the former Riverton ash impoundment has been capped and closed. Final closure as an industrial (coal combustion waste) landfill was approved on June 30, 2014 by the Kansas Department of Health and Environment (KDHE).

On September 30, 2015, the EPA finalized a revision of the Clean Water Act (CWA) Steam Electric Effluent Limitation Guidelines (ELGs) for coal-fired power plants. The new rule sets technology-based ELGs based on the nature of the pollutants being discharged and the facilities involved. As published, beginning in November 2018, the EPA and states would incorporate the new standards into all wastewater discharge permits, including permits for coal ash impoundments. We do not have sufficient information at this time to estimate additional costs at each facility that will result from the new standards to be in effect no later than December 2023. Both our coal ash impoundment and closed landfill are compliant with existing state and federal regulations.

Effective October 19, 2015, the EPA established a final rule to regulate the disposal of coal combustion residuals (CCRs) as a non-hazardous solid waste under subtitle D of the Resource Conservation and Recovery Act (RCRA). We expect compliance with both the CCR and ELG rule to result in the need to construct a new landfill and the conversion of existing bottom ash handling from a wet to a dry system at a potential cost of up to $15 million at our Asbury Power Plant. We expect resulting costs to be recoverable in our rates. Final closure of the existing ash impoundment, for which an asset retirement obligation of $5.4 million has been recorded, is anticipated after the new landfill is operational. Separately, an asset retirement obligation of $4.4 million has been recorded for our interest in the coal ash impoundment at the Iatan Generating Station.

We have received preliminary permit approval in Missouri for a new utility waste landfill adjacent to the Asbury plant. A technical review of our Detailed Site Investigation (DSI) for the specific site has been completed and was approved by the Missouri Department of Natural Resources on June 29, 2015. Receipt of the final construction permit for the CCR waste landfill is expected in October 2016.

Renewable Energy

On November 4, 2008 Missouri voters approved the Clean Energy Initiative (Proposition C) which currently requires Empire and other investor-owned utilities in Missouri to generate or purchase electricity from renewable energy sources, such as solar, wind, biomass and hydro power, or purchase Renewable Energy Credits (RECs), in amounts equal to at least 5% of retail sales in 2014, increasing to at least 15% by 2021. We are currently in compliance with this regulatory requirement as a result of generation from our Ozark Beach Hydroelectric Project and purchased power agreements with Cloud County Windfarm, LLC and Elk River Windfarm, LLC. Proposition C also requires that 2% of the energy from renewable energy sources must be solar; however, we believed that we were exempted by statute from the solar requirement. On January 20, 2013 the Earth Island Institute, d/b/a Renew Missouri, and others challenged our solar exemption by filing a complaint with the MPSC. The MPSC dismissed the complaint and Renew Missouri filed a notice of appeal seeking review by the Missouri Supreme Court. On February 10, 2015 the Missouri Supreme Court issued an opinion holding that the legislature had the authority to adopt the statute providing the exemption but reversed the MPSC's holding that the two laws could be harmonized. The statute providing the exemption (which was enacted in August 2008) was impliedly repealed by the adoption of Proposition C because it conflicted with the latter law. On May 6, 2015, the MPSC approved tariffs we filed on May 5, 2015 to establish solar rebate payment procedures and revise our net metering tariffs to accommodate the payment of solar rebates. As of September 30, 2015, we had processed 109 solar rebate applications resulting in solar rebate-related costs totaling approximately $1.6 million under the new tariff. We have recorded the $1.6 million as a regulatory asset (See Note 3 – Regulatory Matters). The law provides a number of methods that may be utilized to recover the associated expenses. We expect any costs to be recoverable in rates.

Legislation was recently adopted that altered the Kansas renewable portfolio standard (RPS), ending all mandatory requirements in 2015. The mandate, which required 20% of our Kansas retail customer peak capacity requirements to be sourced from renewables by 2020, has been changed to a voluntary goal. We are currently in compliance as a result of purchased power agreements with Cloud County Windfarm, LLC and Elk River Windfarm, LLC.

Note 8 – Retirement and Other Employee Benefits

Net periodic benefit cost, some of which is capitalized as a component of labor cost and some of which is deferred as a regulatory asset, is comprised of the following components and is shown for our noncontributory defined benefit pension plan, our supplemental retirement program (SERP) and other postretirement benefits (OPEB) (in thousands):

	Three months ended September 30,					
	Pension Benefits		SERP		OPEB	
	2015	2014	2015	2014	2015	2014
Service cost	$ 1,816	$ 1,596	$ 33	$ 57	$ 945	$ 737
Interest cost	2,702	2,648	102	117	1,175	1,109
Expected return on plan assets	(3,396)	(3,185)	-	-	(1,272)	(1,207)
Amortization of prior service cost (1)	(157)	105	(10)	(2)	(253)	(253)
Amortization of net actuarial loss (1)	2,835	1,660	168	168	699	268
Net periodic benefit cost	**$ 3,800**	**$ 2,824**	**$ 293**	**$ 340**	**$ 1,294**	**$ 654**

	Nine months ended September 30,					
	Pension Benefits		SERP		OPEB	
	2015	2014	2015	2014	2015	2014
Service cost	$ 5,581	$ 4,850	$ 119	$ 115	$ 2,785	$ 1,950
Interest cost	7,708	8,114	286	290	3,502	3,270
Expected return on plan assets	(10,175)	(9,829)	-	-	(3,897)	(3,600)
Amortization of prior service cost (1)	(472)	314	(32)	(6)	(758)	(758)
Amortization of net actuarial loss (1)	7,525	4,958	448	378	2,061	725
Net periodic benefit cost	**$ 10,167**	**$ 8,407**	**$ 821**	**$ 777**	**$ 3,693**	**$ 1,587**

	Twelve months ended September 30,					
	Pension Benefits		SERP		OPEB	
	2015	2014	2015	2014	2015	2014
Service cost	$ 7,198	$ 6,713	$ 157	$ 148	$ 3,435	$ 2,686
Interest cost	10,413	10,631	383	370	4,592	4,226
Expected return on plan assets	(13,452)	(12,936)	-	-	(5,097)	(4,689)
Amortization of prior service cost (1)	(368)	447	(34)	(8)	(1,011)	(1,011)
Amortization of net actuarial loss (1)	9,178	7,569	574	520	2,303	1,291
Net periodic benefit cost	**$ 12,969**	**$ 12,424**	**$ 1,080**	**$ 1,030**	**$ 4,222**	**$ 2,503**

(1) Amounts are amortized from our regulatory asset originally recorded upon recognizing our net pension liability on the balance sheet.

We provide certain healthcare and life insurance benefits to eligible retired employees, their dependents and survivors through trusts we have established. Participants generally become eligible for retiree healthcare benefits after reaching age 55 with 5 years of service. For employees hired after June 1, 2014, retiree healthcare benefits received upon retirement will no longer be subsidized.

In accordance with our regulatory agreements, our pension funding policy is to make contributions that are at least equal to the greater of either the minimum funding requirements of ERISA or the accrued cost of the plan. We made contributions of $21.4 million during the nine months ended September 30, 2015. No additional contributions are expected for the year. Our OPEB funding policy is to contribute annually an amount at least equal to the actuarial cost of postretirement benefits. We expect to be required to fund approximately $5.0 million during 2015, of which we have made contributions of approximately $3.7 million as of September 30, 2015. The actual minimum pension and OPEB funding requirements will be determined based on the results of the actuarial valuations.

Note 9 – Equity Compensation

Our performance-based restricted stock awards and time-vested restricted stock awards are valued as liability awards, in accordance with fair value guidelines. We allow employees to elect to have taxes in excess of the minimum statutory requirements withheld from their awards and, therefore, the awards are classified as liability instruments under the ASC guidance on share based payment. Awards treated as liability instruments must be revalued each period until settled, and cost is accrued over the requisite service period and adjusted to fair value at each reporting period until settlement or expiration of the award. Grants were made in the first quarter of 2015 (the effect of which is included in the table below) but did not have a material impact on our results of operations. We had unrecognized compensation expense of $0.5 million as of September 30, 2015 which will be recognized over the remaining requisite service period.

We recognized the following amounts in compensation expense and tax benefits for all of our stock-based awards and programs for the applicable periods ended September 30 (in thousands):

	Three Months Ended		Nine Months Ended		Twelve Months Ended	
	2015	2014	2015	2014	2015	2014
Compensation Expense	$ 598	$ 504	$ 1,659	$ 2,372	$ 2,976	$ 2,875
Tax Benefit Recognized	213	180	592	870	1,081	1,050

Time-Vested Restricted Stock Awards

Our time-vested restricted stock awards vest after a three-year period. No dividend rights accumulate during the vesting period. Time-vested restricted stock is valued at an amount equal to the fair market value of our common stock on the date of grant. If employment terminates during the vesting period because of death, retirement, or disability, the participant is entitled to a pro-rata portion of the time-vested restricted stock awards such participant would otherwise have earned, which is distributed six months following the date of termination, with the remainder of the award forfeited. If employment is terminated during the vesting period for reasons other than those listed above, the time-vested restricted stock awards will be forfeited on the date of the termination, unless the Board of Directors Compensation Committee determines, in its sole discretion, that the participant is entitled to a pro-rata portion of the award.

A summary of time-vested restricted stock activity under the plan for 2014 and 2015 is presented in the table below:

	2015		2014	
	Number of shares	Weighted Average Grant Date Fair Value	Number of shares	Weighted Average Grant Date Fair Value
Outstanding at January 1,	41,000	$ 21.89	24,900	$ 22.68
Granted	19,000	30.40	22,600	22.40
Distributed	(1,654)	21.92	(4,010)	22.98
Forfeited shares	(2,746)	25.91	(2,490)	-
Outstanding at September 30	55,600	$ 24.60	41,000	$ 24.15

Performance-Based Restricted Stock Awards

Performance-based restricted stock awards consisting of the right to receive a number of shares of common stock at the end of the restricted period (assuming performance criteria are met) are granted to qualified individuals. We estimate the fair value of outstanding restricted stock awards using a Monte Carlo option valuation model.

Non-vested performance-based restricted stock awards (based on target number) as of September 30, 2015 and 2014 and changes during the nine months ended September 30, 2015 and 2014 were as follows:

	2015		2014	
	Number of shares	**Weighted Average Grant Date Fair Value**	**Number of shares**	**Weighted Average Grant Date Fair Value**
Outstanding at January 1,	63,300	$ 21.74	47,200	$ 21.39
Target shares granted	21,800	$ 30.40	27,000	$ 22.40
Shares issued in excess of target	3,653	$ 30.55	-	-
Shares awarded	(13,653)	$ 30.55	-	-
Forfeited shares	(6,079)	$ 24.10	-	-
Target shares not awarded	0	$ 0	(10,900)	$ 21.84
Granted, nonvested at September 30,	69,021	$ 24.36	63,300	$ 21.74

Employee Stock Purchase Plan

Our Employee Stock Purchase Plan (ESPP) permits the grant to eligible employees of options to purchase common stock at 90% of the lower of market value at date of grant or at date of exercise. The lookback feature of this plan is valued at 90% of the Black-Scholes methodology plus 10% of the maximum subscription price. As of September 30, 2015, there were 764,645 shares available for issuance in this plan.

	2015	2014
Subscriptions outstanding at September 30	59,463	57,915
Maximum subscription price(1)	$21.43	$21.43
Shares of stock issued	56,193	56,942
Stock issuance price	$21.01	$19.58

(1) Stock will be issued on the closing date of the purchase period, which runs from June 1, 2015 to May 31, 2016.

Assumptions for valuation of these shares are shown in the table below.

	2015	2014
Fair value of grants at September 30	$ 3.58	$ 3.07
Risk-free interest rate	0.26%	0.10%
Expected dividend yield	4.40%	4.30%
Expected volatility	21.00%	14.00%
Expected life in months	12	12
Grant Date	6/1/15	6/2/14

Note 10- Regulated Operating Expenses

The following table sets forth the major components comprising "regulated operating expenses" under "Operating Revenue Deductions" on our consolidated statements of income for all periods presented ended September 30 (in thousands):

	Three Months Ended 2015	Three Months Ended 2014	Nine Months Ended 2015	Nine Months Ended 2014	Twelve Months Ended 2015	Twelve Months Ended 2014
Electric transmission and distribution expense	$ 7,325	$ 7,463	$21,839	$21,139	$ 28,619	$ 26,492
Natural gas transmission and distribution expense	592	569	1,997	1,801	2,558	2,496
Power operation expense (other than fuel)	4,258	4,183	13,813	12,195	17,708	15,885
Customer accounts and assistance expense	2,649	2,772	8,142	8,492	10,889	11,350
Employee pension expense (1)	2,769	2,735	8,170	7,963	10,797	10,638
Employee healthcare expense (1)	3,022	2,486	7,640	6,817	9,970	9,150
General office supplies and expense	3,352	3,088	9,032	10,465	13,591	13,725
Administrative and general expense	3,650	3,307	11,647	10,970	15,061	14,479
Allowance for uncollectible accounts	705	915	2,050	3,017	2,453	3,917
Miscellaneous expense	115	255	326	480	448	656
Total	$28,437	$27,773	$84,656	$83,339	$ 112,094	$108,788

(1) Does not include capitalized portion of costs, but reflects the GAAP expensed cost plus or minus costs deferred to and amortized from a regulatory asset and/or a regulatory liability for Missouri, Kansas and Oklahoma jurisdictions.

Note 11– Segment Information

The tables below present statement of income information, balance sheet information and capital expenditures of our business segments.

	For the three months ended September 30, 2015				
	Electric	**Gas**	**Other**	**Eliminations**	**Total**
($-000's)					
Statement of Income Information					
Revenues	$ 162,412	$ 5,084	$ 2,563	$ (345)	$ 169,714
Depreciation and amortization	18,651	984	455	-	20,090
Federal and state income taxes	15,137	(340)	467	-	15,264
Operating income	34,622	413	748	-	35,783
Interest income	1	6	12	(17)	2
Interest expense	10,384	968	-	(17)	11,335
Income from AFUDC (debt and equity)	1,997	3	-	-	2,000
Net income	25,086	(560)	759	-	25,285
Capital Expenditures	$ 39,867	$ 2,009	$ 470		$ 42,346

	For the three months ended September 30, 2014				
	Electric	**Gas**	**Other**	**Eliminations**	**Total**
($-000's)					
Statement of Income Information					
Revenues	$ 164,500	$ 4,989	$ 2,343	$ (320)	$ 171,512
Depreciation and amortization	17,127	966	457	-	18,550
Federal and state income taxes	13,560	(293)	447	-	13,714
Operating income	30,380	647	682	-	31,709
Interest income	2	4	6	(8)	4
Interest expense	9,424	968	-	(8)	10,384
Income from AFUDC (debt and equity)	2,769	2	-	-	2,771
Net income	23,561	(322)	653	-	23,892
Capital Expenditures	$ 60,151	$ 1,628	$ 430		$ 62,209

	For the nine months ended September 30, 2015				
	Electric	**Gas**	**Other**	**Eliminations**	**Total**
($-000's)					
Statement of Income Information					
Revenues	$ 431,335	$ 31,181	$ 7,334	$ (1,035)	$ 468,815
Depreciation and amortization	55,930	2,932	1,375	-	60,237
Federal and state income taxes	26,296	454	1,326	-	28,076
Operating income	70,791	3,629	2,124	-	76,544
Interest income	128	34	33	(53)	142
Interest expense	30,686	2,898	-	(53)	33,531
Income from AFUDC (debt and equity)	5,493	6	-	-	5,499
Net income	43,809	728	2,155	-	46,692
Capital Expenditures	$ 137,977	$ 3,679	$ 1,824		$ 143,480

For the nine months ended September 30, 2014	Electric	Gas	Other	Eliminations	Total
($-000's)					
Statement of Income Information					
Revenues	$ 458,355	$ 36,587	$ 6,985	$ (960)	$ 500,967
Depreciation and amortization	50,493	2,790	1,365	-	54,648
Federal and state income taxes	30,138	1,065	1,281	-	32,484
Operating income	74,091	4,545	2,062	-	80,698
Interest income	34	23	14	(23)	48
Interest expense	28,245	2,893	-	(23)	31,115
Income from AFUDC (debt and equity)	7,036	79	-	-	7,115
Net income	52,271	1,712	2,008	-	55,991
Capital Expenditures	$ 151,764	$ 6,084	$ 1,269		$ 159,117

For the twelve months ended September 30, 2015	Electric	Gas	Other	Eliminations	Total
($-000's)					
Statement of Income Information					
Revenues	$ 565,471	$ 46,437	$ 9,650	$ (1,379)	$ 620,179
Depreciation and amortization	72,971	3,902	1,901	-	78,774
Federal and state income taxes	31,894	1,230	1,689	-	34,813
Operating income	87,188	5,859	2,798	-	95,845
Interest income	131	36	40	(62)	145
Interest expense	40,352	3,865	-	(62)	44,155
Income from AFUDC (debt and equity)	8,290	11	-	-	8,301
Net income	53,005	1,981	2,818	-	57,804
Capital Expenditures	$ 199,189	$ 5,431	$ 2,656		$ 207,276

For the twelve months ended September 30, 2014	Electric	Gas	Other	Eliminations	Total
($-000's)					
Statement of Income Information					
Revenues	$ 588,611	$ 53,406	$ 9,288	$ (1,280)	$ 650,025
Depreciation and amortization	66,937	3,720	1,826	-	72,483
Federal and state income taxes	37,735	1,842	1,719	-	41,296
Operating income	94,978	6,735	2,784	-	104,497
Interest income	72	29	16	(25)	92
Interest expense	37,655	3,857	-	(25)	41,487
Income from AFUDC (debt and equity)	9,062	89	-	-	9,151
Net Income	65,501	2,932	2,721	-	71,154
Capital Expenditures	$ 191,690	$ 7,679	$ 2,381		$ 201,750

As of September 30, 2015	Electric	Gas[1]	Other	Eliminations	Total
($-000's)					
Balance Sheet Information					
Total assets	$2,348,920	$124,499	$ 36,130	$ (46,706)	$2,462,843

[1] Includes goodwill of $39,492.

	As of December 31, 2014				
($-000's)	**Electric**	**Gas[1]**	**Other**	**Eliminations**	**Total**
Balance Sheet Information					
Total assets	$ 2,271,539	$130,856	$ 34,655	$ (46,794)	$2,390,256

[1] Includes goodwill of $39,492.

Note 12– Income Taxes

The following table shows our provision for income taxes (in millions) and our consolidated effective federal and state income tax rates for the applicable periods ended September 30:

	2015	2014	2015	2014	2015	2014
Consolidated provision for income taxes	$ 15.3	$ 13.7	$ 28.1	$ 32.5	$ 34.8	$ 41.3
Consolidated effective federal and state income tax rates	37.6%	36.5%	37.6%	36.7%	37.6%	36.7%

The effective income tax rate for the three, nine and twelve month periods ended September 30, 2015 is higher than comparable periods in 2014 primarily due to lower equity AFUDC income in 2015 compared to 2014.

We do not have any unrecognized tax benefits as of September 30, 2015. We did not recognize any significant interest or penalties in any of the periods presented. We do not expect any significant changes to our unrecognized tax benefits over the next twelve months.

The Tax Increase Prevention Act (the "Act") was signed into law on December 19, 2014. The Act restored several expired business tax provisions, including bonus depreciation for 2014. Due to the reinstatement of bonus depreciation, we generated approximately $74.1 million of tax net operating losses (NOLs) during 2014, resulting in approximately $26.0 million in deferred tax assets. These losses may be carried back two years and are also available to offset future taxable income until 2034. Our 2015 tax liability is expected to be higher than 2014, assuming that congressional action does not extend bonus depreciation. However, we expect to utilize investment tax credits and NOLs to partially offset the 2015 tax payments.

In 2010, we received $17.7 million of investment tax credits based on our investment in Iatan 2. We utilized $0.7 million and $9.0 million of these credits on our 2012 and 2013 tax returns, respectively. Due to the passage of the Act, we were unable to use these credits on our 2014 tax return. We expect to use between $5.0 million and $7.0 million of the remaining credits on our 2015 tax return. The tax credits will have no significant income statement impact because the credits reduce the overall cost of service to our customers by lowering their rates over the life of the plant.

On September 13, 2013, the IRS and the Treasury Department released final regulations under Sections 162(a) and 263(a) on the deduction and capitalization of expenditures related to tangible property. These regulations apply to tax years beginning on or after January 1, 2014, and we utilized the book capitalization method as allowable under the final regulations on our 2014 tax return. Our utilization of the book capitalization method did not have a significant impact on the effective tax rate.

ALGONQUIN POWER & UTILITIES CORP.
Unaudited Pro Forma Consolidated
Financial Statements
As at and for the nine months ended September 30, 2015 and for the year ended December 31, 2014

FOREWORD

UNAUDITED PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS

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 Empire District Electric Company and its subsidiaries (collectively "Empire") under the acquisition method of accounting. The unaudited pro forma consolidated balance sheet gives effect to the Acquisition as if it had closed on September 30, 2015. The unaudited pro forma consolidated statements of operations for the year ended December 31, 2014 and the nine months ended September 30, 2015 give effect to the Acquisition as if it had closed on January 1, 2014.

The unaudited pro forma consolidated financial statements are presented for illustrative purposes only. The pro forma adjustments are based upon available information and certain assumptions that we believe are reasonable in the circumstances, as described in the notes to the unaudited pro forma consolidated financial statements.

Empire is a regulated utility company engaged in electric generation, transmission and distribution delivery and, through a wholly-owned subsidiary, natural gas distribution.

The unaudited pro forma consolidated financial statements are based on Empire's historical consolidated financial statements as at and for the nine months ended September 30, 2015 and for the year ended December 31, 2014.

The pro forma information presented, including allocation of purchase price, is based on preliminary estimates of fair values of assets acquired and liabilities assumed, available information and assumptions may be revised as additional information becomes available. The actual adjustments to the consolidated financial statements upon the closing of the Acquisition will depend on a number of factors, including additional information available and the net assets of Empire on the closing date of the Acquisition. Therefore, the actual adjustments will differ from the pro forma adjustments, and the differences may be material. For example, the final purchase price allocation is dependent on, among other things, the finalization of asset and liability valuations. This final valuation will be based on the actual net tangible and intangible assets and liabilities of Empire that exist as of the closing date of the Acquisition. Any final adjustment may change the allocation of purchase price, which could affect the fair value assigned to the assets and liabilities and could result in a change to the unaudited pro forma consolidated financial statements, including a change to goodwill.

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

CERTIFICATE OF ALGONQUIN POWER & UTILITIES CORP.

Dated: February 15, 2016

This short form prospectus, together with the documents incorporated herein by reference, constitutes full, true and plain disclosure of all material facts relating to the securities offered by this short form prospectus as required by the securities legislation of each of the provinces of Canada.

(Signed) *IAN ROBERTSON* Chief Executive Officer	(Signed) *DAVID BRONICHESKI* Chief Financial Officer

On behalf of the Board of Directors

(Signed) *KENNETH MOORE* Director	(Signed) *CHRISTOPHER JARRATT* Director

CERTIFICATE OF THE UNDERWRITERS

Dated: February 15, 2016

To the best of our knowledge, information and belief, this short form prospectus, together with the documents incorporated herein by reference, constitutes full, true and plain disclosure of all material facts relating to the securities offered by this short form prospectus as required by the securities legislation of each of the provinces of Canada.

CIBC WORLD MARKETS INC.	SCOTIA CAPITAL INC.
(Signed) *DAVID WILLIAMS*	(Signed) *THOMAS I. KURFURST*

BMO NESBITT BURNS INC.	NATIONAL BANK FINANCIAL INC.	RBC DOMINION SECURITIES INC.	TD SECURITIES INC.
(Signed) *GREG PETIT*	(Signed) *IAIN WATSON*	(Signed) *KYLE WALKER*	(Signed) *JOHN KROEKER*

DESJARDINS SECURITIES INC.	RAYMOND JAMES LTD.
(Signed) *FRANCOIS CARRIER*	(Signed) *GRAHAM FELL*

J.P. MORGAN SECURITIES CANADA INC.	WELLS FARGO SECURITIES CANADA, LTD.
(Signed) *DAVID RAWLINGS*	(Signed) *DARIN DESCHAMPS*

INDUSTRIAL ALLIANCE SECURITIES INC.

(Signed) *RICHARD LEGAULT*

CANACCORD GENUITY CORP.	CORMARK SECURITIES INC.
(Signed) *STEVEN WINOKUR*	(Signed) *STEFAN COOLICAN*