CU Inc.

DBRS

James Jung, CFA, FRM, CPA, CMA
+1 416 597 7577
jjung@dbrs.com

Tom Li
+1 416 597 7378
tli@dbrs.com

Insight beyond the rating.

Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A (high)	Confirmed	Stable
Unsecured Debentures & Medium-Term Notes	A (high)	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable
Cumulative Preferred Shares	Pfd-2 (high)	Confirmed	Stable

Rating Rationale

DBRS Limited (DBRS) has confirmed the ratings of CU Inc. (CUI or the Company) as noted above. The confirmation reflects DBRS's expectation that (1) the quality of transmission and distribution regulatory regimes in Alberta, which has shown signs of deterioration in 2015, will remain reasonable for the current rating category; (2) CUI's diversification across different energy segments will continue to support the stability of earnings and cash flow; and (3) overall key credit metrics will remain within the "A" rating category despite the continued large capital expenditure (capex) program over the next two years. The debt-to-cash flow ratio, which is currently at the lower end of the "A" rating range, is expected to improve gradually over the next three years.

DBRS views the quality of regulatory regimes in Alberta as still being above-average in North America, due to the high level of cost certainty and downside protection under normal operating conditions, which mitigate negative effects from lower deemed return on equity (ROE) and equity thickness ratios approved in the Genetic Cost of Capital (GCOC) decision in March 2015 and ongoing Utility Asset Disposition (UAD) legal proceedings. With a robust cost recovery mechanism and operating efficiency, CUI has sustained profitability well above its regulatory return parameters over the past five years (after recognizing assets and liabilities arising from rate-regulated activities). DBRS acknowledges that the recent Electric Transmission 2015 Interim Rates decision was reasonable, approving 90% of CUI's applied electricity transmission requirements for the 2015–2017 test year period. As a result, earnings and operating cash flow are expected to continue to grow steadily, supporting key credit metrics to remain within the "A" rating category. As noted in the DBRS commentary, DBRS Comments on Quality of Regulatory Regimes, dated July 23, 2015, a potential unfavourable UAD court decision alone would not affect CUI's credit ratings. DBRS will assess the magnitude of the stranded cost as a result of an UAD event on a case-by-case basis when such an event materializes.

With the downshifting of Alberta's economy and expected completion of the "big build" associated with electric transmission infrastructure over the next two years, capex will likely further normalize, while earnings and cash flow will benefit from a higher rate base. As a result, DBRS expects free cash flow before dividends to become positive in 2017, and the cash flow-to-debt ratio to gradually recover to around historical levels (15%) more consistent with the current rating category. The rating assumes excess cash, which is not required to maintain the regulatory capital structure, will flow up to its parent company, Canadian Utilities Limited (CU; rated "A" by DBRS).

Financial Information

	6 mos. June 30		12 mos. June 30	For the year ended December 31				
(CA$ millions)	2015	2014	2015	2014	2013	2012	2011	2010
Total debt in capital structure 1	59.7%	59.8%	59.7%	60.2%	57.7%	57.1%	56.2%	55.2%
Cash flow/Total debt 1	12.7%	13.1%	12.7%	12.6%	13.1%	13.6%	14.6%	16.2%
EBIT gross interest coverage (times) 1	2.53	2.69	2.59	2.67	2.70	2.70	2.71	2.61

1 Includes operating leases.

Issuer Description

CU Inc. (CUI) is a holding company whose operating subsidiaries consist of regulated electric transmission and distribution, as well as gas distribution and transmission utilities, serving the areas of Alberta, the Yukon and the Northwest Territories. CUI is wholly owned by Canadian Utilities Limited, which in turn is 53.2% owned by ATCO Ltd. (rated A (low)).

Rating Considerations

Strengths

1. Low-risk regulated electric and gas businesses
CUI operates exclusively as a regulated electric and gas transmission and distribution asset operator in a reasonable regulatory environment, primarily in Alberta.

2. Diversified business lines
CUI's diversification across different energy segments (electric and gas transmission and distribution) supports the stability of earnings and cash flow and reduces risks associated with one single business.

3. Growth in rate base
CUI's rate base in 2016 is expected to be double that of 2011 levels after the completion of the transmission build-out. This is a result of the significant capex spending, which was at approximately six times depreciation in 2014. The Company's earnings and cash flows have seen a substantial increase because of the growing rate base and should continue to benefit going forward.

Challenges

1. Large capex program
The Company is undergoing a period of significant growth capex, which has put some pressure on its financial and credit profile; however, DBRS expects the Company to remain prudent with its financing program to maintain the key financial metrics within its rating range.

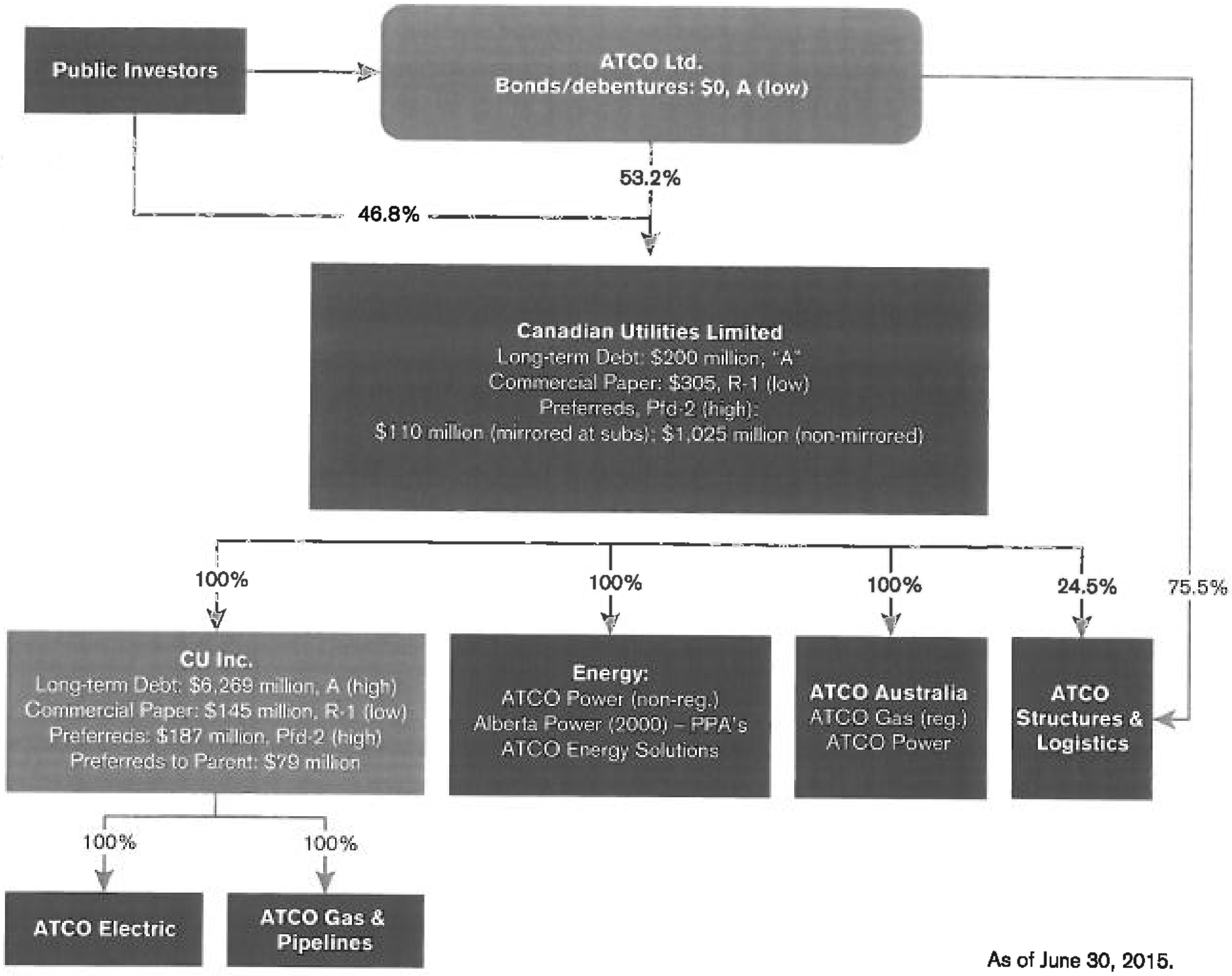
2. Significant external financing requirement
For CUI to maintain its credit profile and regulatory approved capital structure, DBRS expects the sizable free cash flow deficits resulting from the Company's capex to be funded by a combination of external debt, preferred shares, equity injection and/or dividend management from CU over the next two years. As such, a material decline in the credit quality of CU could have a credit impact on CUI.

3. Inflationary/Cost management risk
Under the Performance-Based Regulation (PBR) framework, annual rate increases for ATCO Electric's distribution segment and ATCO Gas are determined by a formula that adjusts for inflation and expected productivity improvements. Operational efficiency will be key during the PBR term (five years) for CUI to meet the productivity factor and earn its allowed return on equity (ROE). There is also additional risk that the Company's costs increase at a faster rate than the set inflation factor.

Major Projects (Potential and Under Construction)

- ***Eastern Alberta Transmission Line Project:*** This project is a 500 kilovolts (kV) high-voltage direct-current transmission line along a corridor on the east side of Alberta between Edmonton and Calgary. The project is estimated to cost approximately $1.8 billion, with $1.7 billion incurred as of December 31, 2014. Construction commenced in late December 2012 and all line construction was complete by Q1 2015, with an expected in-service date by the end of 2015.
- ***Northwest Fort McMurray Transmission Development Project:*** This project includes approximately 140 kilometres (km) of transmission lines and two new sub-stations. The project is estimated to cost $463 million, with $64 million incurred as of December 31, 2014. Final AUC approval on the first substation was received in January 2014, while the second substation is expected to be delayed beyond 2019.
- ***Central East Transmission Development Project:*** This project consists of a number of transmission line and transformer upgrades approximately 300 km northeast of Edmonton. The estimated cost of the project is $340 million, with $312 million incurred as of December 31, 2014. The project has an expected in-service date of 2015.
- ***North East Region Transmission Development:*** This project includes customer-driven enhancements and a 240 kV transmission line in the Fort McMurray area. Approximately $200 million of customer-driven enhancements are expected to be completed by 2016, while a $200 million system enhancement project to strengthen the 240 kV transmission line is expected to be in service in 2018. The timing for the remaining projects remains to be finalized. Of the total estimated cost of $800 million, $106 million has incurred as of December 31, 2014.
- ***Vermillion-Red Deer-Edgerton-Provost Transmission Development:*** The AESO is currently planning for transmission development to upgrade and enhance the reliability and carry capacity in these areas. Total cost for the development is estimated to be $375 million, with $2 million spent as of December 31, 2014.
- ***Urban Pipeline Replacement Project:*** This project is for the replacement and relocation of aging, high-pressure natural gas pipelines in Calgary and Edmonton. The project is estimated to cost $700 million, with $68 million incurred as of December 31, 2014. ATCO Pipelines received approval for the project in January 2014 and expects to complete construction in 2018.

Organizational Chart



As of June 30, 2015.

- CUI is expected to continue to finance its cash flow deficits (driven by large capex commitments) through debt issuances, along with continued support from its parent, CU, through timely equity injections and lower dividend payout requirements.
- The Company is committed to maintaining its leverage at approximately 60% to be in line with its regulatory capital structures and to still be commensurate with the "A" rating range.
- DBRS also expects the Company's cash flow-to-debt ratio to remain above the minimum threshold of 12.5% during the remaining transmission build-out period.

Earnings and Outlook

Consolidated Earnings	6 mos. June 30		12 mos. June 30	For the year ended December 31				
(CA$ millions)	2015	2014	2015	2014	2013	2012	2011	2010
Net sales	1,150	1,079	2,251	2,180	1,949	1,744	1,574	1,482
EBITDA	607	555	1,185	1,133	984	847	750	737
EBIT	416	384	810	778	664	570	501	494
Gross interest expense	165	143	314	292	247	212	185	190
Net income before non-recurring items	225	201	449	425	360	304	259	264
Reported net income	176	256	327	407	372	330	304	234
Return on equity	10.5%	10.3%	10.8%	10.5%	10.0%	10.1%	10.0%	10.8%
Reported Segmented Adjusted Earnings 1								
ATCO Electric	132	128	277	273	223	170	135	115
ATCO Gas	68	45	120	97	81	75	60	88
ATCO Pipelines	19	18	30	29	34	37	46	44
Eliminations	0	0	0	0	0	0	(6)	(4)
	219	**191**	**427**	**399**	**338**	**282**	**235**	**243**

1 Adjusted for rate regulated activities.

2014 Summary

- Earnings in 2014 increased, largely because of continued rate base growth.
- The Company achieved its actual ROE higher than deemed ROE, partially due to operating efficiency.

2015 Outlook

- Earnings in the six months ended June 30, 2015 (H1 2015), continued to benefit from the growing rate base of the transmission segment and operating efficiency, which more than offset the following negative earnings drivers:
- The GCOC decision decreased CUI's deemed return on equity and equity thickness, lowering pre-tax earnings by $41 million (of this amount, $31 million related to 2013 and 2014).
- The Capital Tracker decisions decreased Capital Tracker rates, lowering pre-tax earnings by $12 million (of this amount, $8 million related to 2013 and 2014).
- Despite the prior period adjustments associated with the aforementioned negative earnings impacts, ROE was sustained at over 10% in H1 2015.
- Earnings are expected to continue to grow for the remainder of 2015 as a result of the interim rates decision that approved 90% of CUI's applied electricity transmission requirements for the 2015–2017 period (the decision was received in June 2015).

Financial Profile and Outlook

(CA$ millions)	6 mos. June 30 2015	6 mos. June 30 2014	12 mos. June 30 2015	For the year ended December 31 2014	2013	2012	2011	2010
Net income before non-recurring items	225	201	449	425	360	304	259	264
Depreciation, depletion & amortization	191	171	375	355	320	277	249	243
Deferred income taxes and other	(4)	12	6	22	13	20	2	(23)
Cash flow from operations	**412**	**384**	**830**	**802**	**693**	**601**	**510**	**484**
Dividends paid	(6)	(10)	(12)	(16)	(22)	(22)	(37)	(22)
Capital expenditures	(568)	(967)	(1,605)	(2,004)	(2,114)	(2,092)	(1,288)	(770)
Contributions from customers	121	97	179	155	255	175	115	66
Free cash flow (bef. working cap. changes)	**(41)**	**(496)**	**(608)**	**(1,063)**	**(1,188)**	**(1,338)**	**(700)**	**(242)**
Regulated asset and liabilities change	16	55	(57)	(18)	12	26	45	(30)
Changes in non-cash work. cap. items	(138)	16	(128)	26	(75)	171	105	(9)
Net Free Cash Flow	**(163)**	**(425)**	**(793)**	**(1,055)**	**(1,251)**	**(1,141)**	**(550)**	**(281)**
Proceeds on asset sales	0	0	2	2	2	43	38	16
Net change in debt	145	585	659	1,099	897	865	600	0
Net change in preferreds	0	0	0	(160)	0	0	(20)	75
Net change in equity	0	0	126	126	202	315	0	0
Other investing and financing	6	5	5	4	5	42	15	24
Discontinued operations	0	0	0	0	0	0	0	46
Change in cash	**(12)**	**165**	**(1)**	**16**	**(145)**	**124**	**83**	**(120)**
Short term advances from parent company	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**40**
Total debt	6,414	5,767	6,414	6,291	5,179	4,285	3,447	2,884
Cash and equivalents	10	16	10	44	8	151	0	0
Total debt in capital structure 1	59.7%	59.8%	59.7%	60.2%	57.7%	57.1%	56.2%	55.2%
Cash flow/Total debt 1	12.7%	13.1%	12.7%	12.6%	13.1%	13.6%	14.6%	16.2%
EBIT gross interest coverage (times) 1	2.53	2.69	2.59	2.67	2.70	2.70	2.71	2.61
Dividend payout ratio	2.7%	5.0%	2.7%	3.8%	6.1%	7.2%	14.3%	8.3%

1 Includes operating leases.

2014 Summary

- The Company's key credit metrics remained reasonable for the A rating category although the debt-to-cash flow ratio was at the lower end of the "A" rating range (12.5% to 17.5%).
- Operating cash flow increased, largely because of the growing rate base.
- Capex remained elevated at around $2.0 billion in 2014, which was consistent with the high levels reported in 2013 and 2012. The majority of capex was in the transmission operations, which was predominantly for Alberta Electric System Operator direct-assigned projects.
- Dividends remained very low as CUI's heavy capex limited internally generated cash flow availability.
- As a result of the large capex, CUI generated a free cash flow deficit in 2014. The Company funded this through a mix of debt issuances and equity injections from its parent, CU.

2015 Outlook

- CUI's financial risk profile is expected to remain reasonable for the current rating category.
- Operating cash flow is expected to benefit from continued rate base additions.
- Capex is expected to begin to normalize as large transmission capex projects are complete. Capex is expected to be lower, at around $1.5 billion in 2015.
- With lower capex, CUI is expected to begin to increase dividends.
- The Company is committed to maintaining its leverage at approximately 60% to be in line with its regulatory capital structures and to still be commensurate with the "A" rating range.
- DBRS also expects the Company's cash flow-to-debt ratio to remain above the minimum threshold of 12.5% during the transmission build-out period for the next two years.

Long-Term Debt Maturities and Bank Lines

CU Inc. Credit Facilities (as of June 30, 2015)

(CA$ millions)	Amount	Drawn	Available	Expiry
Revolving credit	900	145	755	2016-2017
Uncommitted	128	21	107	No set mat. date
Total	1,028	166	862	

Liquidity

- CUI's liquidity position remains reasonable and sufficient to fund ongoing operations, with $755 million available in committed revolving credit facilities as of June 30, 2015.
- The Company has a $700 million Commercial Paper (CP) program that is backed by its $900 million revolving credit facility.
- Of the $166 million credit line usage, $145 million was related to issuances of CP.

Long Term Debt Maturities (as of December 31, 2014)

(CA$ millions)	2015	2016	2017	2018	2019	Thereafter	Total
Amount	-	3	150	-	480	5,636	6,269
% of total	0.0%	0.0%	2.4%	0.0%	7.7%	89.9%	100.0%

Summary of Debt

- The Company's debt maturity remains well spread over the next five years, with less than 3% of long-term debt coming due over the next three years.
- The Company continued to have favourable access to the capital markets in 2015 as it took advantage of the current low interest rate environment to primarily fund its capex program. In July 2015, CUI issued $400 million 3.964% debentures due in 2045.
- DBRS expects the Company to access the capital markets less frequently over the medium term, as capex is beginning to normalize in light of slower economic conditions in Alberta.
- The Company has trust indenture covenants, which include the provision that CUI's consolidated indebtedness will not exceed 75% of total capitalization. DBRS does not expect this to restrict the Company's operations going forward or pose any challenges in the near to medium term.

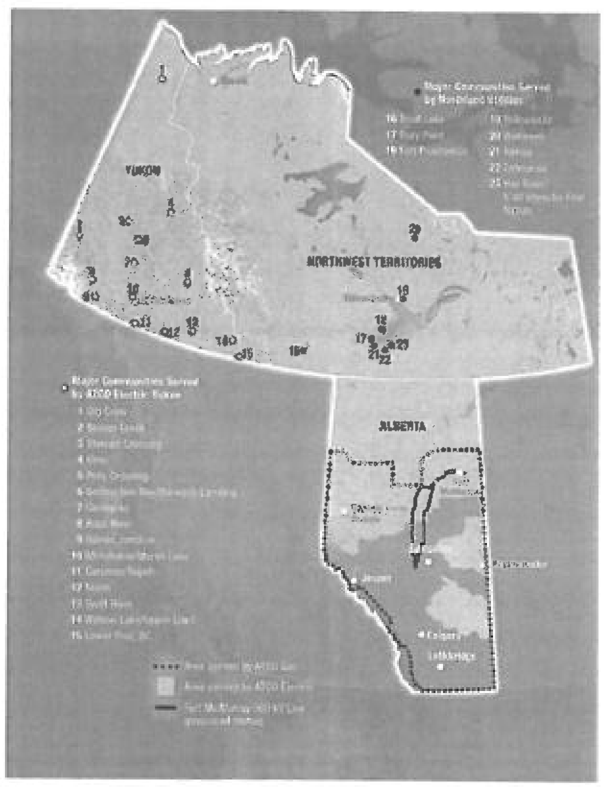
Description of Operations

1. Electric Transmission and Distribution

- This segment serves approximately 248,000 electric customers in Alberta, the Yukon and the Northwest Territories. Electric transmission and distribution is the largest earnings contributor to CUI.

2. Gas Transmission and Distribution

- ATCO Gas and ATCO Pipelines operate gas distribution and transmission businesses serving customers throughout Alberta. ATCO Gas has approximately 1.1 million customers.



Note: Activity areas map excludes ATCO Pipelines.
Source: CU Inc. Annual Information Form 2014.

Regulation

- CUI's Alberta-based utility operations are regulated by the AUC. Utility operations in the Yukon and in the Northwest Territories are regulated by regulatory bodies in their respective jurisdictions.
- DBRS's primary regulatory focus is on Alberta, where most of the Company's earnings are generated.
- DBRS views the quality of regulatory regimes in Alberta as still being above-average in North America, due to the high level of cost certainty and downside protection under normal operating conditions, which more than offset negative effects from regulatory lag, lower deemed return on equity and equity thickness ratios. Earnings and cash flow forecast risks are relatively limited for CUI and its Alberta peers due to: (1) no power price risk; (2) minimal volume risk; (3) a forward-looking test year; (4) a cost-of-service framework for the transmission business; and (5) the ability to re-open and review the PBR application for the distribution business if actual ROE is less than 300 basis points for two consecutive years or 500 basis points for any single year, relative to the approve ROE.
- There have been minimal examples of stranded costs in the regulated Alberta electricity and natural transmission and distribution businesses (including the ATCO Slave Lake decision in October 2014, which resulted in an impairment charge of $0.4 million). However, the AUC concluded that any stranded costs associated with utility assets should not remain in rate base, and that utility companies, rather than ratepayers, should bear the risk of stranded costs. The Court of Appeal heard the UAD appeal case in June 2015 with a decision likely before year-end. However, DBRS views potential material UAD events as being a low-probability, high-impact event (e.g., severe weather conditions). In constructing the procedures and methodologies used for its related ratings, DBRS generally assumes economic stability is the norm over the medium to long term in the absence of major events that cause disruption in the marketplace, such as force majeure. Therefore, in general, a potential unfavourable UAD court decision alone would not affect the CUI's credit ratings. DBRS would assess the magnitude of impact on a case-by-case basis when such an event materializes.

Distribution	Year	Date of decision	Mid-Year Rate Base (CA$ millions)	ROE	Common Equity Ratio
ATCO Electric Distribution	2011	22-Nov-11	1,193	8.75%	39%
	2012	22-Nov-11	1,392	8.75%	39%
	2013	23-Mar-15	N/A*	8.30%	38%
	2014	23-Mar-15	N/A*	8.30%	38%
ATCO Gas	2011	20-Nov-12	1,524	8.75%	39%
	2012	20-Nov-12	1,666	8.75%	39%
	2013	23-Mar-15	N/A *	8.30%	38%
	2014	23-Mar-15	N/A *	8.30%	38%

* The distribution utilities in Alberta are operating under PBR and no longer have an approved mid-year rate base forecast.

- Beginning in 2013, the distribution operations of ATCO Electric and ATCO Gas are regulated based on a PBR framework, which calculates customer rates on an annual basis based on a formula.
- CUI's distribution business operating under PBR is not subject to the revised ROE and deemed equity during the current PBR term (2013–2017). However, the capital tracker and flow-through items will be influenced by the lower regulatory parameters.
- Under the new PBR framework, a revenue-per-customer cap for gas distribution companies and a price cap for electric distribution companies are employed to recognize the differences between the two industries. As a result, the distribution operation of ATCO Electric is exposed to volume risk, while ATCO Gas faces limited volume risk.
- The PBR formula also incorporates a capital tracker mechanism for capex beyond normal investments.
- The AUC directed ATCO Electric and ATCO Gas to re-file their 2013 Capital Tracker Applications in a December 2013 decision. The decision provided more clarity on the capital tracker mechanism and a better understanding of the AUC's assessment process. ATCO Electric and ATCO Gas re-filed their 2013 applications, along with their 2014–2015 CTAs, in May 2014. Final decisions, which were received in Q1 2015, included approval of incremental funding for substantially all of the applied for Capital Tracker programs.
- Under PBR, the distribution operations of ATCO Electric and ATCO Gas will likely also experience greater cost-cutting pressure (but reasonable and manageable) to meet or exceed the PBR's productivity factor. Operational efficiency is crucial to achieving higher earnings under PBR.

Regulation (CONTINUED)

Transmission	Year	Date of decision	Mid-Year Rate Base (CA$ millions)	ROE	Common Equity Ratio
ATCO Electric Transmission	2011	22-Nov-11	1,940	8.75%	37%
	2012	22-Nov-11	2,839	8.75%	37%
	2013	23-Mar-15	3,576	8.30%	36%
	2014	23-Mar-15	4,413	8.30%	36%
ATCO Pipelines	2011	20-Dec-11	825	8.75%	45%
	2012	30-Aug-13	847	8.75%	38%
	2013	23-Mar-15	879	8.30%	37%
	2014	23-Mar-15	979	8.30%	37%

- The transmission operations of ATCO Electric and ATCO Pipelines are regulated based on a cost-of-service methodology, which allows the Company to recover all prudently estimated operating expenses and earn a reasonable return on approved capital investments.
- CUI's electricity transmission division filed an application with the AUC on March 16, 2015, requesting approval of its forecast transmission tariff for the 2015–2017 Test Years, as shown in the table below.

CA$ millions	2015	2016	2017
Transmission Tariffs	694.3	810.8	913.3
Increase	115.3	116.5	102.5
Annual % Increase	19.9%	16.8%	12.6%

- Given the decline in pressure on CUI's credit metrics currently being experienced, the Company is proposing to discontinue some of the temporary relief measures, including the discontinuation of recovery of Federal Future Income Taxes (and refund of Federal Future Income Tax amount collected in prior years) and recovery of the capitalized portion of pension costs (and refund of capitalized portion of pension costs collected in prior years).
- The Company is proposing the continuation of recovery of Transmission Direct Assigned Construction Work in Progress (CWIP) in rate base.
- ATCO Pipelines files its 2015–2016 GTA in December 2014, requesting revenues of approximately $215 million for 2015 and $250 million for 2016.

Retail

- The Company is also required to provide retail services to small and medium customers who are eligible for the regulated rate option (RRO). Under the current system, utilities can appoint a designated retailer to provide retail services to RRO customers.
- CUI has no direct exposure to gas or power price risk, as all of its customers purchase gas or power from the default supplier (Direct Energy) or a competitive retailer of their choice.
- The risk of retailers' failure on their payment obligations is mitigated by the retailers having investment-grade credit ratings or by security deposits from the retailers. In the event that a distribution utility incurs credit losses, such utility may apply to the regulator to recover these bad debts in rates.

Assessment of Regulatory Environment

Regulatory Assessment – Distribution Business

Criteria	Score	Analysis
1. Deemed Equity	Excellent Good Satisfactory **Below Average** Poor	AUC allows CUI's distribution business to have a deemed equity of 38%, which has historically been relatively consistent. CUI generally maintains its actual capital structure in line with the regulatory capital structure.
2. Allowed ROE	Excellent Good **Satisfactory** Below Average Poor	CUI currently has an allowed ROE of 8.30%. DBRS expects earnings from CUI's regulated businesses to achieve or exceed the approved ROE.
3. Energy Cost Recovery	**Excellent** Good Satisfactory Below Average Poor	There is no power price risk for CUI's regulated distribution businesses, as it is not responsible for purchasing power from generation facilities or the wholesale market. RRO providers and competitive retail providers are responsible for procuring power and ensuring that costs are passed on to end users at the rate set by the AUC (for regulated rate providers) or by a contract with a retailer. Cost recovery occurs on a monthly basis through the billing system.
4. Capital Cost Recovery	Excellent **Good** Satisfactory Below Average Poor	Major capital costs are pre-approved by the AUC and recovered through distribution rates. Subsequent capital spending after the base year can be applied for each year through the capital trackers if (a) capex is not part of the ongoing operations of the utility, (b) spending is for replacement of capital assets or required by a third party and (c) it has a material impact on finances.
5. COS vs. IRM	Excellent Good **Satisfactory** Below Average Poor	CUI's distribution business regulated based on a PBR framework, which calculates customer rates annually based on a formula for a five-year period.
6. Political Interference	Excellent Good Satisfactory **Below Average** Poor	The Government of Alberta plays a significant role in the electricity sector in Alberta. As a result, the government has direct and indirect influence in Alberta's electricity industry.
7. Retail Rate	Excellent Good **Satisfactory** Below Average Poor	The cost of power in Alberta is billed to customers by regulated and retail rate providers at rates set by the AUC or rates determined by retail contracts. The regulated rate is calculated based on the month-ahead prices, introducing more volatility in the rates. Average prices for residential customers in major cities in Alberta was around 12 to 13 cents per kilowatt hour (kWh) for a monthly consumption of 1,000 kWh, in effect April 1, 2014.
8. Stranded Cost Recovery	Excellent **Good** Satisfactory Below Average Poor	There have been minimal examples of stranded costs in the Alberta electricity market; however, with Decision 2011-474 with regard to the UAD, the AUC concluded that any stranded costs associated with transmission assets should not remain in rate base and that utility companies, rather than ratepayers, should bear the risk of stranded costs. The Court of Appeal in Alberta heard the UAD appeal case in June 2015 with a decision likely before year-end.
9. Rate Freeze	Excellent Good **Satisfactory** Below Average Poor	Distribution rates were frozen for a short time in early 2012, but this did not have a material impact on CUI's financial profile.
10. Market Structure (Deregulation)	Excellent **Satisfactory** Poor	The Alberta electricity market was restructured in 1996 to separate generation, transmission and distribution operations. The generation industry is a deregulated market, while distribution and transmission remains fully regulated under the AUC. As a result of the deregulated power market, retailers and generation companies are subject to power price and counterparty risk.

Assessment of Regulatory Environment (CONTINUED)

Transmission Business Regulatory Assessment

Criteria	Score	Analysis
1. Deemed Equity	Excellent Good Satisfactory **Below Average** Poor	The AUC allows CUI's transmission business to have a deemed equity of 36%, which has historically been relatively consistent. CUI generally maintains its actual capital structure in line with the regulatory capital structure.
2. Allowed ROE	Excellent Good **Satisfactory** Below Average Poor	CUI currently has an allowed ROE of 8.30%. DBRS expects earnings from CUI's regulated businesses to achieve or exceed the approved ROE.
3. Energy Cost Recovery	**Excellent** Good Satisfactory Below Average Poor	There is no power price risk for CUI's regulated transmission businesses, as it is not responsible for purchasing power from generation facilities or the wholesale market.
4. Capital Cost Recovery	Excellent **Good** Satisfactory Below Average Poor	Major capital costs are pre-approved by the AUC and recovered through transmission rates.
5. COS vs. IRM	**Excellent** Good Satisfactory Below Average Poor	CUI's transmission service is regulated based on a COS methodology, which allows the Company to recover all prudently estimated operating expenses and earn a reasonable return on approved capital investments.
6. Political Interference	Excellent Good Satisfactory **Below Average** Poor	The Government of Alberta plays a significant role in the electricity sector in Alberta. As a result, the government has direct and indirect influence in Alberta's electricity industry.
7. Retail Rate	Excellent Good **Satisfactory** Below Average Poor	The cost of power in Alberta is billed to customers by regulated and retail rate providers at rates set by the AUC or rates determined by retail contracts. The regulated rate is calculated based on the month-ahead prices, introducing more volatility in the rates. Average prices for residential customers in major cities in Alberta was around 12 to 13 cents per kilowatt hour (kWh) for a monthly consumption of 1,000 kWh in effect April 1, 2014.
8. Stranded Cost Recovery	Excellent **Good** Satisfactory Below Average Poor	There have been minimal examples of stranded costs in the Alberta electricity market, however, with Decision 2011-474 with regard to the UAD, the AUC concluded that any stranded costs associated with transmission assets should not remain in rate base and that utility companies, rather than ratepayers, should bear the risk of stranded costs. The Court of Appeal in Alberta heard the UAD appeal case in June 2015 with a decision likely before year-end.
9. Rate Freeze	Excellent Good **Satisfactory** Below Average Poor	Transmission rates were frozen for a short time in early 2012, but this did not have a material impact on CUI's financial profile.
10. Market Structure (Deregulation)	Excellent **Satisfactory** Poor	The Alberta electricity market was restructured in 1996 to separate generation, transmission and distribution operations. The generation industry is a deregulated market, while distribution and transmission remains fully regulated under the AUC. As a result of the deregulated power market, retailers and generation companies are subject to power price and counterparty risk.

CU Inc.

Balance Sheet
(CA$ millions)

	June. 30	Dec. 31		
Assets	**2015**	**2014**	**2013**	**2012**
Cash & equivalents	10	44	8	151
Accounts receivable	256	344	314	291
Inventories	63	60	66	59
Prepaid expenses & other	26	13	14	19
Total Current Assets	355	461	402	520
Net fixed assets	12,958	12,536	10,869	9,058
Future income tax assets	0	0	0	0
Goodwill & intangibles	386	383	332	284
L.T. adv. to affiliate corp.	130	130	130	10
Other L.T. assets	13	12	11	130
Total Assets	**13,842**	**13,522**	**11,744**	**10,002**

	June. 30	Dec. 31		
Liabilities & Equity	**2015**	**2014**	**2013**	**2012**
S.T. borrowings	145	22	2	0
Accounts payable	465	671	602	632
Current portion L.T.D.	0	0	100	3
Other current liab.	0	0	0	0
Total Current Liab.	610	693	704	635
Long-term debt	6,269	6,269	5,077	4,282
Deferred income taxes	875	743	628	520
Other L.T. liab.	1,698	1,599	1,461	1,245
Preferred shares	266	266	422	422
Shareholders' equity	4,124	3,952	3,452	2,698
Total Liab. & SE	**13,842**	**13,522**	**11,744**	**10,002**

Balance Sheet & Liquidity Capital Ratios

	6 mos. June 30		12 mos. June 30	For the year ended December 31				
	2015	**2014**	**2015**	**2014**	**2013**	**2012**	**2011**	**2010**
Current ratio	0.58	0.29	0.58	0.67	0.57	0.82	0.88	0.68
Total debt in capital structure	59.4%	59.4%	59.4%	59.9%	57.2%	56.3%	56.0%	53.9%
Total debt in capital structure 1	59.7%	59.8%	59.7%	60.2%	57.7%	57.1%	56.2%	55.2%
Cash flow/Total debt	12.8%	13.3%	12.9%	12.7%	13.4%	14.0%	14.8%	16.8%
Cash flow/Total debt 1	12.7%	13.1%	12.7%	12.6%	13.1%	13.6%	14.6%	16.2%
(Cash flow-dividends)/Capex (times)	0.91	0.43	0.57	0.43	0.38	0.30	0.40	0.66
Dividend payout ratio	2.7%	5.0%	2.7%	3.8%	6.1%	7.2%	14.3%	8.3%
Coverage Ratios (times)								
EBIT gross interest coverage	2.52	2.69	2.58	2.66	2.69	2.69	2.71	2.60
EBIT gross interest coverage 1	2.53	2.69	2.59	2.67	2.70	2.70	2.71	2.61
EBITDA gross interest coverage	3.68	3.88	3.77	3.88	3.98	4.00	4.05	3.88
Fixed-charge coverage	2.52	2.69	2.58	2.66	2.69	2.69	2.30	2.24
Profitability Ratios								
EBITDA margin	52.8%	51.4%	52.6%	52.0%	50.5%	48.6%	47.6%	49.7%
EBIT margin	36.2%	35.6%	36.0%	35.7%	34.1%	32.7%	31.8%	33.3%
Profit margin	19.6%	18.6%	19.9%	19.5%	18.5%	17.4%	16.5%	17.8%
Return on equity	10.5%	10.3%	10.8%	10.5%	10.0%	10.1%	10.0%	10.8%
Return on capital	5.8%	5.9%	6.0%	5.9%	5.9%	6.1%	6.4%	7.2%

1 Includes operating leases.

Rating History

Debt	Current	2014	2013	2012	2011	2010
Issuer Rating	A (high)	A (high)	A (high)	A (high)	NR	NR
Unsecured Debentures & Medium-Term Notes	A (high)	A (high)	A (high)	A (high)	A (high)	A (high)
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Cumulative Preferred Shares	Pfd-2 (high)	Pfd-2 (high)	Pfd-2 (high)	Pfd-2 (high)	Pfd-2 (high)	Pfd-2 (high)

Notes:
All figures are in Canadian dollars unless otherwise noted.

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Canadian Utilities Limited

James Jung, CFA, FRM, CPA, CMA
+1 416 597 7577
jjung@dbrs.com

Tom Li
+1 416 597 7378
tli@dbrs.com

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Ratings

Debt	Rating	Rating Action	Trend
Commercial Paper	R-1 (low)	Confirmed	Stable
Issuer Rating	A	Confirmed	Stable
Unsecured Debentures	A	Confirmed	Stable
Cum. Preferred Shares	Pfd-2 (high)	Confirmed	Stable

Rating Update

DBRS Limited (DBRS) has confirmed the ratings of Canadian Utilities Limited (CU or the Company) as noted above. The ratings of CU are supported by predictable earnings from its regulated subsidiaries, which are expected to account for approximately 80% of consolidated earnings over the next several years. However, the ratings assume that earnings contribution from the regulated business will gradually decrease to around 70% (but still higher than its historical weighting of 60%) of consolidated earnings over the long term with (1) the downshifting of Alberta's economy and expected completion of the "big build" associated with electric transmission infrastructure over the next two years and (2) the Company's focus on contracted, non-regulated business opportunities in Canada, Mexico and Australia. Although CU's non-regulated segment provides a source of earnings growth and diversification benefits, it also entails higher business risk than that of the regulated utility business. CU's non-regulated business is challenged by lower long-term earnings visibility and recontracting risk.

Maintaining a conservative balance sheet and strong liquidity are the anchors to mitigate the higher risk inherent in the non-regulated business segment. DBRS views CU's leverage and liquidity as being supportive of the current ratings. Long-term debt levels at the holding company (on a deconsolidated basis) were low, at $200 million as at June 30, 2015, and the amount of commercial paper (CP) outstanding has been within the current CP limit of $500 million ($305 million as at June 30, 2015). As a result of low deconsolidated leverage, CU's ability to meet interest obligations has been strong. CU's non-consolidated debt-to-capital ratio has remained well below the DBRS 20% threshold over the past five years. Pro forma for the $125 million preferred issuance in August 2015, the Company's non-consolidated debt-to-capital ratio would be approximately 13%.

CU's Cum. Preferred Shares rating will likely be pressured first should non-consolidated leverage reach near the 20% threshold, while the other ratings could still remain intact. DBRS includes one-notch uplift in the Cum. Preferred Shares rating of CU, largely because of low leverage and the permanent nature of strong cash balances supported by the Company's liquidity policy. CU is committed to maintaining minimum cash balances equivalent to one year of common dividends, plus one year of preferred share dividends and interest payments not covered from the Utilities business. As a result, CU is expected to maintain material cash balances of around $350 million to $500 million over the next several years, providing a significant source of liquidity. However, rising leverage in excess of the 20% threshold could take away the one notch uplift, resulting in a downgrade of the Cum. Preferred Shares rating to Pfd-2, which generally corresponds with companies whose Issuer Ratings are rated "A."

Financial Information

Canadian Utilities Ltd. (Consolidated)

	6 mos. June 30		12 mos. June 30	For the year ended December 31				
(CA$ millions)	2015	2014	2015	2014	2013	2012	2011	2010
Total debt in capital structure 1	61.2%	60.9%	61.2%	60.4%	60.1%	60.6%	58.8%	52.2%
Cash flow/Total debt 1	11.6%	14.4%	12.9%	14.4%	15.4%	15.9%	16.9%	21.0%
EBIT gross interest coverage (times) 1	2.51	2.88	2.79	2.98	3.33	3.19	3.60	3.63
Fixed-charge coverage	2.08	2.33	2.29	2.42	2.64	2.57	2.86	2.89

1 Including operating leases.

Issuer Description

Canadian Utilities Limited is a holding company with principal operating subsidiaries engaged in the following business activities: (1) Utilities (pipelines, natural gas and electricity transmission and distribution) and (2) Energy (power generation and sales, industrial water infrastructure, natural gas gathering, processing, storage and liquids extraction).

Rating Considerations

Strengths

1. Predictable cash flow from low-risk regulated electric and gas subsidiaries

The ratings of CU are supported by predictable earnings from the regulated utility subsidiaries, which are expected to account for approximately 80% of consolidated earnings over the next several years.

2. Low leverage for a holding company structure

Long-term debt levels at the holding company (on a deconsolidated basis) were low, at $200 million as at June 30, 2015, and are expected to remain the same in the foreseeable future. The amount of CP outstanding has been within the current CP limit of $500 million ($305 million as at June 30, 2015). As a result of low leverage, CU's ability to meet interest obligations has been strong. Pro forma for the $125 million preferred issuance in August 2015, the Company's non-consolidated debt-to-capital ratio of approximately 13% was well within DBRS's 20% threshold for holding companies.

3. Strong liquidity

Liquidity at CU has been strong, reflecting sizable credit facilities and cash balances. CU is committed to maintaining minimum cash balances equivalent to one year of common dividends, plus one year of preferred share dividends and interest payments not covered from the Utilities business. As a result, CU is expected to maintain cash balances of around $350 million to $500 million over the next several years, providing significant sources of liquidity. In addition, the Company has a $300 million credit facility with a two-year term (expires November 2016) and a $600 million credit facility with a four-year term (expires November 2018). These credit facilities backstop CU's $500 million CP program.

Challenges

1. Structural subordination

Debt at CU is effectively subordinate to debt at its subsidiaries. This accounts for the one-notch differential in the ratings of CU and its primary subsidiary, CU Inc. (CUI; rated A (high) with a Stable trend by DBRS).

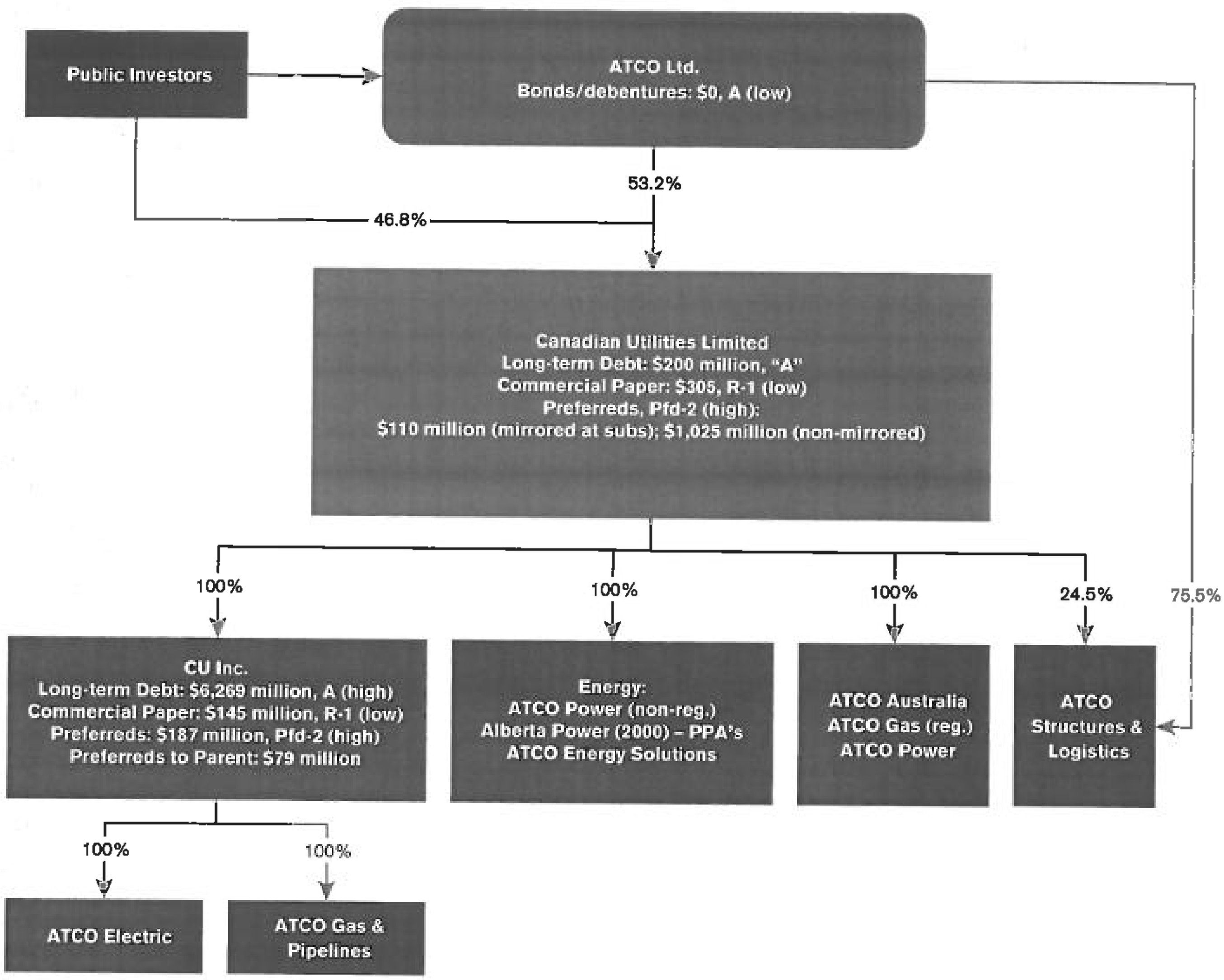
2. Exposure to non-regulated operations

CU's non-regulated operations are viewed to be higher risk compared to CU's regulated utility operations, largely due to the volatility in earnings and cash flows, as well as recontracting risk.

3. Large capital expenditure program

Capital expenditure (capex) is expected to remain elevated, and could pressure financial metrics. While the utility capex program is expected to continue to normalize (as the "big build" associated with electric transmission infrastructure in Alberta is expected to come to an end over the next two years), the Company aims to focus its efforts on developing long-term contracted projects in the non-regulated business to support continued earnings growth.

Organizational Chart



- CU is expected to continue to financially support CUI through timely equity injections and lower dividend payout requirements.
- With the additional preferred issuance of $125 million in August 2015, the size of CU's preferred shares (on a deconsolidated basis) increased to $1,260 million from $1,135 million as at June 30, 2015.
- CU's long-term debt (on a deconsolidated basis) has remained at $200 million since 2013 and is expected to remain the same in the foreseeable future.
- CU's Cum. Preferred Shares rating will likely be pressured first should non-consolidated leverage reach near the 20% threshold, while the other ratings could still remain intact.
- Pro forma for the $125 million preferred issuance in August 2015, the Company's non-consolidated debt-to-capital ratio would be approximately 13%.
- DBRS includes one-notch uplift in the Cum. Preferred Shares rating of CU, largely because of low leverage and the permanent nature of strong cash balances supported by the Company's liquidity policy. CU is committed to maintaining minimum cash balances equivalent to one year of common dividends, plus one year of preferred share dividends and interest payments not covered from the Utilities business. As a result, CU is expected to maintain material cash balances of around $350 million to $500 million over the next several years, providing a significant source of liquidity.
- However, rising leverage in excess of the 20% threshold could take away the one notch uplift, resulting in a downgrade of the Cum. Preferred Shares rating to Pfd-2, which generally corresponds with companies whose Issuer Ratings are rated "A."

Consolidated Earnings and Outlook

Consolidated

(CA$ millions)	6 mos. June 30 2015	6 mos. June 30 2014	12 mos. June 30 2015	For the year ended December 31 2014	2013	2012	2011	2010
Net sales	1,463	1,514	2,990	3,041	2,929	2,663	2,440	2,182
EBITDA	734	792	1,503	1,561	1,542	1,356	1,266	1,171
EBIT	484	555	1,006	1,077	1,080	944	896	835
Gross interest expense	194	193	362	361	323	295	247	229
Net income before non-recurring items	260	305	580	625	630	578	506	490
Reported net income	221	345	600	724	606	572	515	448
Return on equity	9.2%	11.3%	10.5%	11.4%	12.9%	13.5%	12.8%	12.9%

Reported Adjusted Segment Earnings

	6 mos. June 30 2015	6 mos. June 30 2014	12 mos. June 30 2015	2014	2013	2012	2011	2010
Utilities (gas & electric)	219	191	437	409	338	282	236	242
Energy	18	47	70	99	151	136	164	130
ATCO Australia	10	21	40	51	45	43	19	16
Corporate & Other	(17)	12	(13)	16	38	52	48	40
Eliminations	1	1	0	0	0	2	4	5
Adjusted earnings	231	272	534	575	572	515	471	433

2014 Summary

- Earnings in 2014 were relatively flat. Higher earnings contribution from the Utilities segment (primarily due to higher rates and a growing rate base) was offset by weaker earnings from the Energy segment (largely due to lower spark spreads and price volatility that negatively affected merchant power plants; two of CU's legacy coal units came off long-term contract at the end of 2013).
- The gap between net income before non-recurring items and reported net income was largely because of an after-tax gain of $138 million on sale of ATCO I-Tek's information technology service business, which was partly offset by impairments of $28 million on certain natural gas gathering, process and liquids extraction assets in Canada, as well as ATCO Power Australia's Bulwer Island power station.

2015 Outlook

- Earnings from the Utilities segment are expected to continue to benefit from the growing rate base of the transmission segment and operating efficiency, which should more than offset recent regulatory decisions that negatively affected earnings (i.e., the Genetic Cost of Capital and the Capital Tracker decisions in Alberta).
- The Energy segment's earnings are expected to deteriorate in 2015 from 2014, largely due to lower Alberta wholesale power prices and a global slow-down in resource-based economies.
- The ATCO Australia segment's earnings are expected to weaken in 2015 from 2014. The negative regulatory decision released in July 2015 with respect to ATCO Gas Australia's next Access Arrangement period from July 2014 to December 2019 lowered pre-tax earnings by $19 million in the six months ended June 30, 2015. Among other things, the decision resulted in a reduced return on equity to 7.28% from 10.4%.
- The Corporate & Other segment earnings are expected to weaken in 2015 from 2014, mainly due to the sale of the Company's information technology services business in Q3 2014.
- Earnings in 2015 are expected to weaken as a result of expected lower earnings contribution from the Energy and ATCO Australia segments, more than offsetting expected higher earnings from the Utilities segment.

Consolidated Financial Profile

Consolidated

(CA$ millions)	6 mos. June 30 2015	6 mos. June 30 2014	12 mos. June 30 2015	For the year ended December 31 2014	2013	2012	2011	2010
Net income before non-recurring items	260	305	580	625	630	578	506	490
Depreciation, depletion & amortization	250	250	514	514	478	412	370	336
Deferred income taxes and other	(25)	(7)	(10)	8	(2)	(14)	31	(27)
Cash flow from operations	**485**	**548**	**1,084**	**1,147**	**1,106**	**976**	**907**	**799**
Dividends paid on preferreds	(29)	(34)	(58)	(63)	(64)	(54)	(49)	(43)
Dividends paid on common equity	(156)	(140)	(297)	(281)	(250)	(226)	(206)	(190)
Capital expenditures	(586)	(927)	(1,680)	(2,021)	(2,067)	(2,038)	(1,242)	(763)
Free cash flow (bef. working cap. changes)	**(286)**	**(553)**	**(951)**	**(1,218)**	**(1,275)**	**(1,342)**	**(590)**	**(197)**
Regulated asset and liabilities change	32	51	(43)	(24)	3	3	45	(28)
Changes in non-cash work. cap. items	(185)	(54)	(180)	(49)	35	134	137	18
Net Free Cash Flow	**(439)**	**(556)**	**(1,174)**	**(1,291)**	**(1,237)**	**(1,205)**	**(408)**	**(207)**
Acquisitions	(10)	0	(45)	(35)	0	0	(315)	0
Proceeds on asset sales	0	5	218	223	2	7	3	16
Amount to be financed	**(449)**	**(551)**	**(1,001)**	**(1,103)**	**(1,235)**	**(1,198)**	**(720)**	**(191)**
Net change in debt	441	555	925	1,039	879	923	562	(112)
Net change in preferreds	0	(160)	0	(160)	400	0	225	75
Net change in equity	51	64	94	107	137	60	4	(1)
Other investing and financing	1	(10)	(21)	(32)	(34)	(22)	2	(27)
Change in cash	**44**	**(102)**	**(3)**	**(149)**	**147**	**(237)**	**73**	**(256)**
Total debt	7,768	6,896	7,768	7,319	6,293	5,474	4,730	3,404
Cash and equivalents	352	354	352	306	452	325	576	512
Total debt in capital structure 1	61.2%	60.9%	61.2%	60.4%	60.1%	60.6%	58.8%	52.2%
Cash flow/Total debt 1	11.6%	14.4%	12.9%	14.4%	15.4%	15.9%	16.9%	21.0%
EBIT gross interest coverage (times) 1	2.51	2.88	2.79	2.98	3.33	3.19	3.60	3.63
Fixed-charge coverage	2.08	2.33	2.29	2.42	2.64	2.57	2.86	2.89
Dividend payout ratio	71.2%	57.0%	61.2%	55.0%	49.8%	48.4%	50.4%	47.6%

1 Including operating leases.

2014 Summary

- CU's credit metrics have weakened largely as a result of the large capex program at the Utilities segment.
- Operating cash flow improved, largely driven by the growing rate base at the Utilities segment.
- High capex mainly stemmed from the continued investments in the Company's regulated distribution and transmission businesses.
- Dividends increased approximately 12% to $281 million in 2014 from $$250 million in 2013. Stripping out the effect of $104 million that was reinvested under the Dividend Reinvestment Plan (DRIP), net cash dividends were lower at $177 million.
- The ongoing significant capex resulted in a large free cash flow deficit, which was funded with a mix of debt and DRIP.

2015 Outlook

- CU's key credit metrics further weakened in H1 2015, largely due to the challenging merchant power market in Alberta and a global slow-down in resource-based economies.
- Operating cash flow will likely remain relatively flat as higher operating cash flow from the Utilities segment is expected to be offset by lower contributions from the Energy and ATCO Australia segments.
- Capex is expected to be lower, at around $1.9 billion in 2015. The Company expects to invest approximately $1.8 billion in regulated utility and commercially secured capital growth projects and the remaining balance is expected to be mainly general corporate capex spread across the Company.
- Dividends are expected to remain relatively stable at around $280 million.
- CU's net free cash flow deficit is expected to continue to be funded with a mix of non-recourse debt, CP (to be within the CP limit of $500 million; no long-term debt to be issued at the CU level), preferred shares and DRIP.

Non-Consolidated Financial Profile

Non-consolidated

	For the year ended December 31				
	2014	2013	2012	2011	2010
Total debt in capital structure 1	7.0%	9.2%	6.4%	7.2%	5.4%
Cash flow/Interest (times)	16.39	24.68	17.78	31.65	10.70
Cash flow/ (Interest + Preferred dividends) (times)	2.55	4.51	3.77	7.42	2.57
Cash flow/Total debt 1	35.0%	45.9%	54.4%	89.1%	41.5%

1 DBRS treats preferred shares within 20% of common equity as equity, and any amount above 20% as debt.

- CU's non-consolidated adjusted total debt-to-capital ratio has remained well below the DBRS 20% threshold over the past five years.
- Pro forma for the $125 million preferred issuance in August 2015, the Company's non-consolidated debt-to-capital ratio would be approximately 13%.
- Dividends from subsidiaries have been more than sufficient to pay interest on the Company's debt and to pay dividends on its preferred shares.

Long-Term Debt Maturities and Bank Lines

Canadian Utilities Limited (Unconsolidated) Lines of Credit as of June 30, 2015

(CA$ millions)	Amount	Drawn	Available	Expiry
Long-term committed	900	305	595	Nov. 2016/2018
Uncommitted	160	77	83	N/A
Total	**1,060**	**382**	**678**	

Liquidity

- Liquidity at CU has been strong, reflecting sizable credit facilities and cash balances.
- CU is committed to maintaining minimum cash balances equivalent to one year of common dividends, plus one year of preferred share dividends and interest payments not covered from the Utilities business. As a result, CU is expected to maintain cash balances of around $350 million to $500 million over the next several years, providing a significant source of liquidity.
- The Company has a $300 million credit facility with a two-year term (expires November 2016) and a $600 million credit facility with a four-year term (expires November 2018). These credit facilities backstop CU's $500 million CP program.
- CU has $160 million in uncommitted credit facilities used primarily for letters of credit issuances. As at June 30, 2015, the Company had approximately $77 million of outstanding letters of credit.

Canadian Utilities Limited (Unconsolidated) Long Term Debt Maturities as of June 30, 2015

(CA$ millions)	Effective Interest Rate	Amount
2012 3.122% Debenture due November 2022, unsecured	3.187%	200
		200

Summary of Debt

- CU's financial flexibility and liquidity remains strong, with only $200 million of debt at the holding company level, which matures in November 2022.
- DBRS does not expect CU to issue any additional long-term debt at the holding company level in the foreseeable future.

Canadian Utilities Ltd. (Consolidated)

Balance Sheet

(CA$ millions)

Assets	June 30 2015	December 31 2014	December 31 2013	Liabilities and Equity	June 30 2015	December 31 2014	December 31 2013
Cash & equivalents	352	306	452	S.T. borrowings	450	4	2
Accounts receivable	399	465	477	Accounts payable	550	829	777
Inventories	76	85	90	Current portion L.T.D.	19	98	177
Prepaid expenses & other	120	128	86	Other current liab.	57	49	68
Total Current Assets	**947**	**1,004**	**1,105**	**Total Current Liab.**	**1,076**	**980**	**1,024**
Net fixed assets	15,188	14,808	12,905	Long-term debt	7,299	7,217	6,114
Intangibles	399	396	370	Deferred income taxes	882	740	651
Future income tax assets	0	0	0	Provisons	567	582	412
Investment in ASL	201	203	190	Deferred revenue & other L.T. liab.	1,689	1,576	1,456
Finance lease receivable	288	290	319	Preferred shares	1,302	1,302	1,456
Other L.T. assets	195	201	162	Common equity	4,403	4,305	3,936
Total Assets	**17,218**	**16,702**	**15,051**	**Total Liab. & SE**	**17,218**	**16,702**	**15,051**

Balance Sheet & Liquidity & Capital Ratios

	6 mos. June 30 2015	6 mos. June 30 2014	12 mos. June 30 2015	For the year ended December 31 2014	2013	2012	2011	2010
Current ratio	0.88	0.54	0.88	1.02	1.08	1.17	1.47	1.83
Total debt in capital structure	57.7%	56.2%	57.7%	56.6%	53.8%	55.6%	53.1%	47.7%
Total debt in capital structure 1	61.2%	60.9%	61.2%	60.4%	60.1%	60.6%	58.8%	52.2%
Cash flow/Total debt	12.5%	15.9%	14.0%	15.7%	17.6%	17.8%	19.2%	23.5%
Cash flow/Total debt 1	11.6%	14.4%	12.9%	14.4%	15.4%	15.9%	16.9%	21.0%
(Cash flow-dividends)/Capex (times)	0.51	0.40	0.43	0.40	0.38	0.34	0.52	0.74
Dividend payout ratio	71.2%	57.0%	61.2%	55.0%	49.8%	48.4%	50.4%	47.6%
Coverage Ratios (times)								
EBIT gross interest coverage	2.49	2.88	2.78	2.98	3.34	3.20	3.63	3.65
EBIT gross interest coverage 1	2.51	2.88	2.79	2.98	3.33	3.19	3.60	3.63
EBITDA gross interest coverage	3.78	4.10	4.15	4.32	4.77	4.60	5.13	5.11
Fixed-charge coverage	2.08	2.33	2.29	2.42	2.64	2.57	2.86	2.89
Profitability Ratios								
EBITDA margin	50.2%	52.3%	50.3%	51.3%	52.6%	50.9%	51.9%	53.7%
EBIT margin	33.1%	36.7%	33.6%	35.4%	36.9%	35.4%	36.7%	38.3%
Profit margin	17.8%	20.1%	19.4%	20.6%	21.5%	21.7%	20.7%	22.4%
Return on equity	9.2%	11.3%	10.5%	11.4%	12.9%	13.5%	12.8%	12.9%
Return on capital	5.5%	6.9%	6.0%	6.7%	7.5%	7.9%	8.1%	8.7%
Approved Return on Equity								
ATCO Electric (T&D)	8.30%	8.30%	8.30%	8.30%	8.30%	8.75%	8.75%	9.00%
ATCO Gas	8.30%	8.30%	8.30%	8.30%	8.30%	8.75%	8.75%	9.00%
ATCO Pipelines	8.30%	8.30%	8.30%	8.30%	8.30%	8.75%	8.75%	9.00%

1 Including operating leases.

Rating History

	Current	2014	2013	2012	2011	2010
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Issuer Rating	A	A	A	A	A	A
Unsecured Debentures	A	A	A	A	A	A
Cum. Preferred Shares	Pfd-2 (high)	Pfd-2 (high)	Pfd-2 (high)	Pfd-2 (high)	Pfd-2 (high)	Pfd-2 (high)

Previous Action

- Confirmed, October 2, 2014

Related Research

- CU Inc., Rating Report, August 12, 2015.
- DBRS Comments on Quality of Regulatory Regimes in Alberta, July 23, 2015
- DBRS Comments on Rising Regulatory Risk in Alberta, March 25, 2015

Commercial Paper Limited

- $500 million

Previous Report

- Canadian Utilities Limited, Rating Report, October 2, 2014

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on **www.dbrs.com**.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

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Rating Report

ATCO Ltd.

DBRS

James Jung, CFA, FRM, CPA, CMA
+1 416 597 7577
jjung@dbrs.com

Tom Li
+1 416 597 7378
tli@dbrs.com

Insight beyond the rating.

Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A (low)	Confirmed	Stable
Short-Term Issuer Rating Preferred Shares	R-1 (low)	Confirmed	Stable

Rating Update

DBRS has confirmed the Issuer Rating and Short-Term Issuer Rating of ATCO Ltd. (ATCO or the Company) at A (low) and R-1 (low), respectively, both with Stable trends. ATCO's credit profile is largely based on the credit rating of Canadian Utilities Limited (CU, rated "A") given that the majority of the Company's earnings and operating cash flow come from its 53.2% equity investment in CU. ATCO's exposure in the higher-risk non-regulated operations remains manageable and relatively unchanged over the past year. DBRS expects ATCO to continue to manage these high-risk operations selectively in such a way that they will not represent a significant portion of consolidated earnings but will rather provide a source of complementary earnings growth and diversification benefits. The one-notch differential in the ratings of ATCO and CU reflects structural subordination at ATCO with respect to CU.

Earnings for the six months ended June 30, 2015 (H1 2015), were down approximately 22% to $135 million from $172 million in H1 2014, largely because of a sharp decline in earnings contribution from ATCO's non-regulated operations. Negative earnings drivers were a global slow-down in resource-based economies and lower spark spreads and price volatility that negatively affected merchant power plants in Alberta, which more than offset the improved operating performance of the regulated utility operations in Alberta.

Despite the weak operating performance in H1 2015, credit metrics have remained reasonable for the current rating category, with the debt-to-capital at approximately 56%, EBIT interest coverage at 2.7 times and the cash flow-to-debt at 12.9% on a consolidated basis. On a non-consolidated basis, the balance sheet has also remained reasonable with ATCO carrying minimal amounts of debt. ATCO's non-consolidated debt-to-capital was well within DBRS's 20% threshold over the past five years (0% as at June 30, 2015; 0.3% as at December 31, 2014). ATCO has no bonds/debentures issued at the parent level and is not expected to have any long-term debt or preferred securities at this level.

Liquidity has been strong, reflecting ATCO's available credit facilities and cash balances. ATCO is committed to maintaining minimum cash balances equivalent of one year of common dividends, plus one year of preferred share dividends and interest payments not covered from regulated utilities businesses. As a result, ATCO is expected to maintain cash balances of around $100 million to $150 million at the parent level over the next several years, providing significant sources of liquidity.

Financial Information

ATCO Ltd. (Consolidated)	6 mos. June 30		12 mos. June 30	For the year ended December 31				
(CA$ millions)	2015	2014	2015	2014	2013	2012	2011 1	2010
Total debt in capital structure 2 3	56.0%	55.0%	56.0%	54.8%	52.5%	54.2%	51.6%	46.8%
Cash flow/Total debt 2	12.9%	16.8%	14.6%	16.8%	19.1%	20.0%	22.6%	25.8%
EBIT gross interest coverage (times) 2	2.71	3.20	2.99	3.25	3.71	3.67	3.99	3.37

1 Balance sheet figures as of January 1, 2012.
2 Including operating leases.
3 Adjusted for other accumulated comprehensive income.

Issuer Description

ATCO Ltd. (ATCO) is a diversified holding company whose primary investments are in Utilities (pipeline, natural gas and electricity transmission and distribution), Energy (power generation and sales, industrial water infrastructure, natural gas gathering, processing, storage and liquids extraction) and Structures & Logistics (manufacturing, logistics and noise abatement).

Rating Considerations

Strengths

1. Strong investment in low-risk regulated utility
The ratings of ATCO are supported by predictable earnings from the regulated utility subsidiaries which are expected to account for approximately 80% of consolidated earnings over the next several years.

2. Low leverage for a holding company structure
ATCO has no bonds/debentures at the holding company level. Dividend requirements are well covered by the dividends from CU.

3. Strong liquidity
Liquidity at ATCO has been strong, reflecting sizable credit facilities and cash balances. ATCO is expected to maintain cash balances of around $100 million to $150 million over the next several years, providing a significant source of liquidity. In addition, the Company has a $200 million credit facility with a four-year term ($200 million available as at June 30, 2015; expires November 2018).

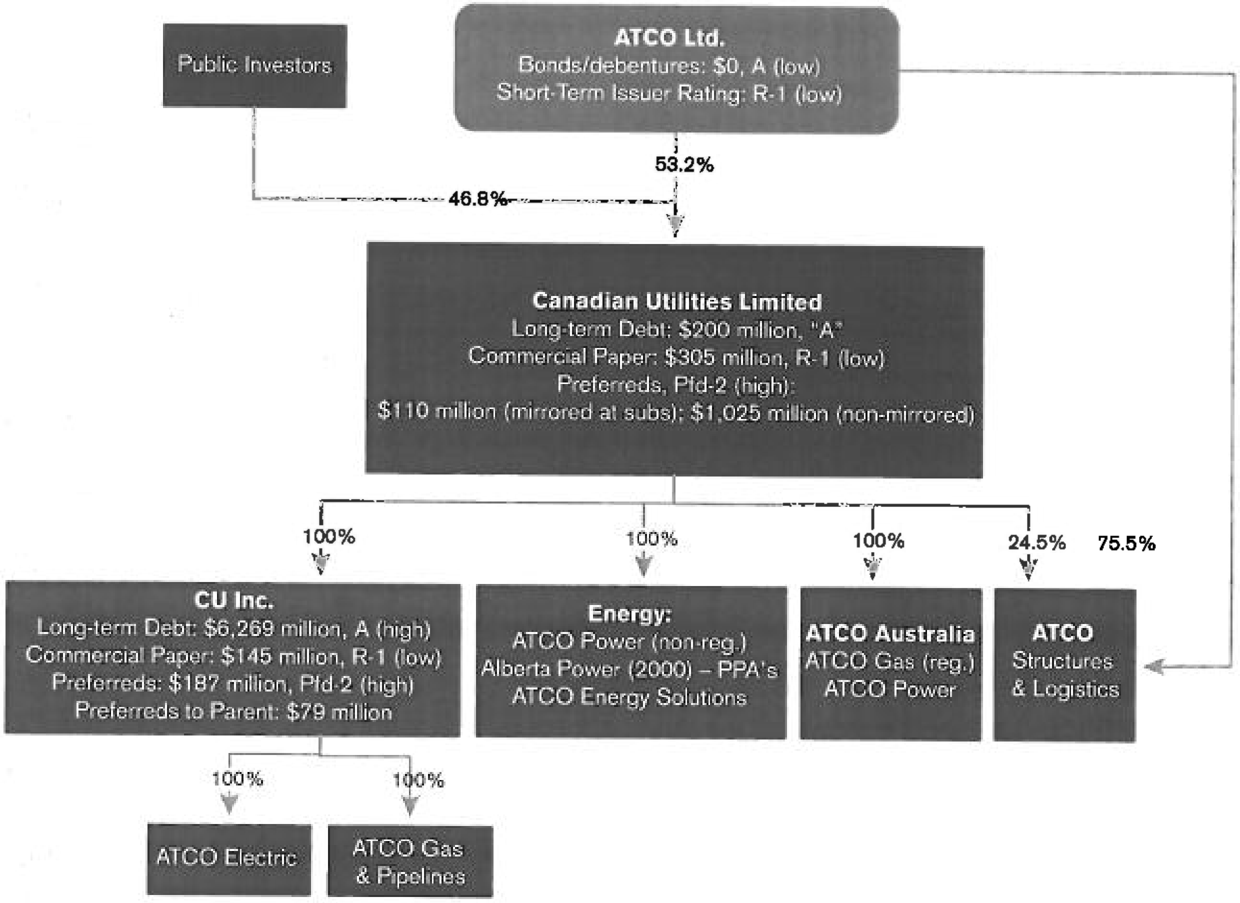
Challenges

1. Structural subordination
The one-notch differential in the ratings of ATCO and CU reflects structural subordination at ATCO with respect to CU.

2. Higher risk in logistics business
ATCO Structures and Logistics Ltd. (75.5% directly owned by ATCO; 24.5% indirectly owned through CU) operates in highly competitive and cyclical environments, with some currency and political risks. The continued global slowdown in resource-based economies have negatively affected ASL's operating performance over the past 12 months (accounted for approximately 13% of reported adjusted earnings for the 12 months ended June 30, 2015)

3. Large capital expenditures (capex) at flagship operating subsidiary, CU
Capex is expected to remain elevated, and could pressure financial metrics on a consolidated basis. While the utility capex program is expected to continue to normalize (as the "big build" associated with electric transmission infrastructure in Alberta is expected to come to an end over the next two years), the Company aims to focus its efforts on developing long-term contracted projects in the non-regulated business to support continued earnings growth.

Organizational Chart



As of June 30, 2015.

- ATCO has no bonds/debentures issued at the parent level and is not expected to have any long-term debt or preferred securities at this level.

Consolidated Earnings and Outlook

ATCO Ltd. (Consolidated)	6 mos. June 30		12 mos. June 30	For the year ended December 31				
(CA$ millions)	2015	2014	2015	2014	2013	2012	2011 1	2010
Net sales	1,636	1,736	3,359	3,459	3,365	3,105	2,883	2,440
EBITDA	792	888	1,616	1,712	1,731	1,567	1,440	1,193
EBIT	527	627	1,081	1,181	1,217	1,100	1,019	802
Gross interest expense	195	195	362	362	325	297	250	237
Earning before taxes	387	477	790	880	922	847	807	614
Income taxes	128	127	216	215	227	202	230	149
Minority interest and equity earnings	124	178	250	304	310	263	270	238
Net income before non-recurring items	135	172	324	361	385	382	307	227
Reported net income	102	193	329	420	418	370	327	286
Reported Segmented Adjusted Earnings								
Structures and Logistics	3	24	46	67	96	115	89	89
Utilities	117	101	234	218	179	148	124	124
Energy	10	25	38	53	80	72	86	86
ATCO Australia	5	11	21	27	24	23	10	10
Corporate & Other	0	10	4	14	10	12	19	19
Sub Total	135	171	343	379	389	370	328	328
Intersegment	0	1	(6)	(5)	1	2	2	3
Reported Adjusted Earnings	135	172	337	374	390	372	330	331

2014 Summary

- Earnings in 2014 were relatively flat. Higher earnings contribution from the Utilities segment (primarily due to higher rates and a growing rate base) was offset by weaker earnings from the Structures and Logistics and Energy segment, largely because of a global slow-down in resource based economies and lower spark spreads and price volatility that negatively affected merchant power plants (two of CU's legacy coal units came off long-term contract at the end of 2013).
- The gap between net income before non-recurring items and reported net income was largely because of an after-tax gain of $74 million on sale of ATCO I-Tek's information technology service business which was partly offset by impairments of $15 million on certain natural gas gathering, process and liquids extraction assets in Canada, as well as ATCO Power Australia's Bulwer Island power station.

2015 Outlook

- Earnings from the Utilities segment are expected to continue to benefit from the growing rate base of the transmission segment and operating efficiency, which should more than offset recent regulatory decisions that negatively affected earnings (i.e., the Genetic Cost of Capital and the Capital Tracker decisions in Alberta).
- The Structures and Logistics segment's earnings should improve in H2 2015 because of additional modular structures project work that will contribute to earnings later in 2015.
- The Energy segment's earnings are expected to deteriorate in 2015 from 2014, largely due to lower Alberta wholesale power prices and a global slowdown in resource-based economies.
- The ATCO Australia segment's earnings are expected to weaken in 2015 from 2014. The negative regulatory decision released in July 2015 with respect to ATCO Gas Australia's next Access Arrangement period from July 2014 to December 2019, lowered pre-tax earnings by $19 million in the six months ended June 30, 2015. Among other things, the decision resulted in a reduced return on equity from 10.4% to 7.28%.
- Earnings in 2015 are expected to weaken as a result of expected lower earnings contribution from the Energy and ATCO Australia segments, more than offsetting expected higher earnings from the Utilities segment.

Consolidated Financial Profile

ATCO Ltd. (Consolidated)	6 mos. June 30		12 mos. June 30	For the year ended December 31				
(CA$ millions)	2015	2014	2015	2014	2013	2012	2011 1	2010
Net income before non-recurring items	135	172	324	361	385	382	307	227
Depreciation & amortization	285	274	572	561	530	471	421	391
Minority interest and equity earnings	119	179	311	371	318	270	270	238
Deferred income taxes and other	(17)	(9)	(22)	(14)	44	43	125	95
Cash flow from operations	522	616	1,185	1,279	1,277	1,166	1,123	951
Dividends paid	(57)	(50)	(106)	(99)	(86)	(75)	(66)	(67)
Capital expenditures	(627)	(955)	(1,792)	(2,120)	(2,137)	(2,253)	(1,376)	(862)
Free cash flow (bef. working cap. changes)	(162)	(389)	(713)	(940)	(996)	(1,162)	(319)	22
Changes in non-cash work. cap. items	(171)	(58)	(169)	(56)	(9)	127	74	8
Adjustments for Rate Regulated Activities	17	27	(23)	(13)	(1)	0	23	(15)
Net Free Cash Flow	(316)	(420)	(905)	(1,009)	(1,006)	(1,035)	(222)	15
Acquisitions & long-term investments	(10)	0	(45)	(35)	0	0	(315)	0
Proceeds on asset sales	0	5	221	226	135	7	7	16
Amount to be financed	(326)	(415)	(729)	(818)	(871)	(1,028)	(530)	31
Net equity change	1	(155)	(4)	(160)	403	(15)	213	(99)
Net debt change	427	518	910	1,001	920	954	574	(151)
Other	(65)	(87)	(152)	(174)	(181)	(173)	(147)	(157)
Change in cash	37	(139)	25	(151)	271	(262)	110	(376)
Total debt	7,821	6,965	7,821	7,388	6,397	5,538	4,594	3,515
Cash and equivalents	574	554	574	552	690	437	381	602
Total debt in capital structure 2 3	56.0%	55.0%	56.0%	54.8%	52.5%	54.2%	51.6%	46.8%
Cash flow/Total debt 2	12.9%	16.8%	14.6%	16.6%	19.1%	20.0%	22.6%	25.8%
EBIT gross interest coverage (times) 2	2.71	3.20	2.99	3.25	3.71	3.67	3.99	3.37
Dividend payout ratio	42.2%	29.1%	32.7%	27.4%	22.3%	19.6%	21.5%	29.5%

1 Balance sheet figures as of January 1, 2012.
2 Including operating leases. (3) Adjusted for other accumulated comprehensive income.

2014 Summary

- ATCO's credit metrics have weakened moderately in 2015 from 2014, largely because of the continued large capex program at the Utilities segment.
- Operating cash flow was relatively flat as the improved operating performance of the Utilities segment was offset by weaker contributions from the non-regulated business.
- High capex mainly stemmed from the continued investments in its regulated distribution and transmission business.
- Dividends increased moderately by $13 million to $99 million (up 15% from 2013). In each of the last four years, ATCO has increased its quarterly dividend by 15%.
- The ongoing significant capex resulted in a large free cash flow deficit. The free cash flow deficit was funded with a mix of debt and dividend reinvestment plan (DRIP) at the CU and the operating company levels.

2015 Outlook

- ATCO's key credit metrics further weakened in H1 2015, largely due to the challenging merchant power market in Alberta and a global slow-down in resource based economies.
- Operating cash flow will likely weaken as higher operating cash flow from the Utilities segment is expected to be offset by lower contributions from the Structures and Logistics, Energy, and ATCO Australia segments.
- Capex is expected to begin to normalize as large transmission capex projects are complete. Capex is expected to be lower, at around $1.9 billion in 2015. The Company expects to invest approximately $1.8 billion in regulated utility and commercially secured capital growth projects and the remaining balance is expected to be mainly maintenance capex spread across the Company.
- Dividend is expected to rise by 15% to around $115 million in 2015 from 2014. This is in line with the historical 15% dividend growth rate over the past four years.
- ATCO's net free cash flow deficit is expected to continue to be funded with a mix of non-recourse debt, preferred and DRIP at the CU and operating company level.
- ATCO has no bonds/debentures issued at the parent level and is not expected to have any debt or preferred securities at this level.

Long-Term Debt Maturities and Bank Lines

Lines of Credit

(CA$ millions)	Total	Used	Available	Expiry
Long-term committed	200.00	-	200.00	November 2018
Uncommitted	17.40	0.80	16.60	N/A
	217.40	0.80	216.60	

As at June 30, 2015

Liquidity

- ATCO has no bonds/debentures issued at the parent level and is not expected to have any debt at the parent level in the foreseeable future.
- The Company has a $200 million credit facility with a four-year term ($200 million available as at June 30, 2015; expires November 2018).
- ATCO utilizes its uncommitted lines of credit from time to time for general corporate purposes.

Consolidated Balance Sheet and Financial Ratios

(CA$ millions)	June. 30 2014	Dec. 31 2013	Dec. 31 2012		June. 30 2014	Dec. 31 2013	Dec. 31 2012
Assets				**Liabilities & Equity**			
Cash & equivalents	574	552	690	S.T. borrowings	450	5	2
Accounts receivable	604	744	713	Accounts payable	659	974	921
Inventories	109	110	131	Current portion L.T.D.	19	98	177
Prepaid expenses & other	153	143	118	Other current liab.	72	72	93
Total Current Assets	**1,440**	**1,549**	**1,652**	**Total Current Liab.**	**1,200**	**1,149**	**1,193**
Net fixed assets	15,701	15,117	13,381	Long-term debt	7,352	7,285	6,218
Goodwill & intangibles	489	487	458	Deferred income taxes	916	778	684
Future income tax assets	0	0	0	Provisions	599	617	442
Finance lease receivable	288	290	319	Other L.T. liab.	1,692	1,580	1,460
Other L.T. assets	230	246	200	Minority Interest	3,134	3,112	3,153
				Shareholders' equity	3,255	3,168	2,860
Total Assets	**18,148**	**17,689**	**16,010**	**Total Liab. & SE**	**18,148**	**17,689**	**16,010**

Balance Sheet &	6 mos. June 30		12 mos. June 30	For the year ended December 31				
Liquidity & Capital Ratios	**2015**	**2014**	**2015**	**2014**	**2013**	**2012**	**2011 1**	**2010**
Current ratio	1.20	0.76	1.20	1.35	1.38	1.34	1.64	1.86
Total debt in capital structure	55.0%	53.7%	55.0%	54.1%	51.5%	52.9%	49.6%	45.7%
Total debt in capital structure 2 3	56.0%	55.0%	56.0%	54.8%	52.5%	54.2%	51.6%	46.8%
Cash flow/Total debt	13.3%	17.7%	15.2%	17.3%	20.0%	21.1%	24.4%	27.1%
Cash flow/Total debt 2	12.9%	16.8%	14.6%	16.8%	19.1%	20.0%	22.6%	25.8%
(Cash flow-dividends)/Capex (times)	0.74	0.59	0.60	0.56	0.54	0.48	0.77	1.03
Dividend payout ratio	42.2%	29.1%	32.7%	27.4%	22.3%	19.6%	21.5%	29.5%
Coverage Ratios (times)								
EBIT gross interest coverage (times)	2.70	3.22	2.99	3.26	3.74	3.70	4.08	3.38
EBITDA gross interest coverage (times)	4.06	4.55	4.46	4.73	5.33	5.28	5.76	5.03
Fixed-charges coverage	2.70	3.22	2.99	3.26	3.74	3.70	4.08	3.29
EBIT gross interest coverage 2	2.71	3.20	2.99	3.25	3.71	3.67	3.99	3.37
Profitability Ratios								
EBITDA margin	48.4%	51.2%	48.1%	49.5%	51.4%	50.5%	49.9%	48.9%
EBIT margin	32.2%	36.1%	32.2%	34.1%	36.2%	35.4%	35.3%	32.9%
Profit margin	8.3%	9.9%	9.6%	10.4%	11.4%	12.3%	10.6%	9.3%
Return on equity	4.3%	5.7%	5.2%	5.9%	7.0%	8.0%	6.9%	5.4%
Return on capital 3	3.4%	4.4%	3.8%	4.3%	4.9%	5.6%	5.4%	4.8%

1 Balance sheet figures as of January 1, 2012.
2 Including operating leases. (3) Adjusted for other accumulated comprehensive income.

Rating History

	Current	2014	2013	2012	2011	2010
Issuer Rating	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)
Short-Term Issuer Rating	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)

Previous Action(s)

- Confirmed, October 7, 2014.

Related Research

- Canadian Utilities Limited, Rating Report, August 25, 2015
- DBRS Comments on Quality of Regulatory Regimes in Alberta, July 23, 2015
- DBRS Comments on Rising Regulatory Risk in Alberta, March 25, 2015

Previous Report

- ATCO Ltd., Rating Report, October 7, 2014

Notes:
All figures are in Canadian dollars unless otherwise noted.

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Research Update:

ATCO Ltd. And Subsidiaries Outlook To Negative From Stable On Weaker Operating Environment, Forecast Financial Metrics

Primary Credit Analyst:
Stephen R Goltz, Toronto (416) 507-2592; stephen.goltz@standardandpoors.com

Secondary Contact:
Andrew Ng, Toronto (416) 507-2545; andrew.ng@standardandpoors.com

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Research Update:

ATCO Ltd. And Subsidiaries Outlook To Negative From Stable On Weaker Operating Environment, Forecast Financial Metrics

Overview

- We are revising our outlook to negative from stable on Calgary, Alta.-based ATCO Ltd. and its subsidiaries Canadian Utilities Ltd (CU Ltd.) and CU Inc.
- We are also affirming our 'A' long-term corporate credit rating on ATCO and its subsidiaries.
- The negative outlook reflects our view that ATCO's planned capital program could put pressure on the company's financial metrics, affecting our positive comparable rating analysis modifier on the company.

Rating Action

On July 7, 2015, Standard & Poor's Ratings Services revised its outlook to negative from stable on Calgary, Alta.-based ATCO Ltd. (ATCO), and its subsidiaries Canadian Utilities Ltd. (CU Ltd.) and CU Inc.

We base the outlook revision on our view that the company's forecast financial metrics in the context of a more difficult Alberta operating environment, as well as its aggressive capital program, weaken the rationale for our positive comparable rating modifier on the company. Recent regulatory decisions also put additional pressure on the company's revenue and cash flow.

At the same time, Standard & Poor's affirmed its 'A' long-term corporate credit rating on ATCO and its subsidiaries. We consider CU Ltd. and CU Inc. to be "core" to ATCO under our group rating methodology criteria in which the ratings and outlooks are equalized with those on the parent.

Rationale

We currently apply a positive comparable rating analysis (CRA) modifier to ATCO based on our view of the company's ability to execute a long-term growth strategy that consistently delivers prudent growth while maintaining stable cash flow credit metrics at the mid-to-high end of the significant range on our medial volatility table. We believe that the operating environment for ATCO in Alberta has weakened because of a number of factors. We expect the price of power will remain weak given the current oversupply of capacity in Alberta and slowed demand growth linked to depressed oil prices. Alberta spot electricity prices have averaged about C$30 per megawatthour for the previous 12 months. Moreover, with the Alberta government's recent announcement

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regarding CO2 emissions, we believe that the operating environment will remain challenging.

We expect the company to invest heavily in the next few years, similar to the past three, with approximately C$8 billion from 2015 to 2017. However, we do not see this level of growth abating beyond 2017. Furthermore, although supported by long-term contracts, not all of the future spending will be regulated. Our forecast expects development of the water infrastructure and liquids storage project in Alberta, a natural gas pipeline and cogeneration power plant in Mexico, and the Fort McMurray West Transmission Project.

The outcome of the Alberta Utilities Commission's (AUC) latest decisions also affect ATCO's revenue and recovery of prudent capital spending contributing additional pressure on cash flow stability. These decisions included the generic cost of capital decision, in which equity thickness and return on equity were lowered by 100 basis points (bps) and 45 bps, respectively, and retroactively applied to previous years in 2013 and 2014; as well as the utility asset disposition ruling that equity investors need to bear the risk of stranded assets instead of ratepayers.

Because of the above factors, we forecast the company's credit metrics will continue to deteriorate through 2017. We forecast ATCO's adjusted funds from operations (AFFO)-to-debt will be at the lower end of the "significant" range (based on our medial volatility table), at about 14% in 2015, and only marginally improving to about 15% in 2016. This continues the deterioration we've seen in the past couple of years with AFFO-to-debt of 15.3% in 2014 down from 18.2% in 2013. Despite the company spending largely on regulated rate-based expansion in the past few years, we do not foresee ATCO moving away from the medial table given the company's nonregulated holdings and planned investments.

We continue to assess the business risk profile of ATCO as "excellent." We believe CU Inc.'s Alberta-based regulated utilities will continue to generate stable cash flow, which we expect to increase to more than 70% of consolidated cash flow at the ATCO level in the next few years, anchoring the business risk profile. However, CU Inc. is predominantly exposed to a single regulator, the AUC, so does not benefit from meaningful regulatory diversity.

We expect ATCO Power, which operates in an environment with "moderately high" industry risk will contribute approximately 10%-15% of cash flows with some variability. ATCO Power's level of fleet contractedness of about 60% (based on generating capacity), strong counterparties, and amortizing project-financed nonrecourse debt in its independent power projects somewhat offset the higher industry risk. The fleet is concentrated in Alberta but has what we view as a good operational track record. ATCO Structures and Logistics' cash flow is typically project-focused, so the company has near-term cash flow visibility. It has more variable long-term cash flow that is influenced by commodity pricing and the macroeconomic environment, which drive the need for this business' products and services. Cash flow from this segment accounts for about 5%-10% of consolidated cash flow.

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The "strong" management and governance score for the group has no direct impact on the ratings but reflects our assessment of management's consistently conservative approach to risk mitigation, with policies and a track record of keeping cash on hand; a stable, long-term strategic horizon compared with that of peers; demonstrated operational effectiveness; and no history of earnings or cash flow surprises.

Our base-case scenario assumes the following:

- Capital programs will be brought into service on time and on budget with about C$7 billion-C$8 billion from 2015 to 2017
- The regulatory regime will be relatively stable and ATCO will not experience any material, adverse regulatory decisions
- The company will continue to earn its allowed returns on its various utility holdings

Based on these assumptions, we arrive at the following credit measures:

- AFFO-to-debt of 14%-15% over the next two years
- Debt-to-EBITDA of about 4.7x over the next two years

Our use of a positive CRA modifier reflects our view of the company's ability to execute a long-term strategy that consistently delivers stable growth. Moreover, such growth has been in the context of conservative management with measured acquisition and growth strategies.

With the application of our group rating methodology, we assess the group credit profile to be equal to that of ATCO, at 'a'. Because we view CU Ltd. and CU Inc. to be "core" to the group, we have equalized our ratings on them with those on ATCO. CU Ltd. and CU Inc. are considered core to the ATCO group primarily because both entities are unlikely to be sold and have a strong long-term commitment of support from ATCO's senior management. In addition, both subsidiaries operate in lines of business integral to ATCO's group strategy (diversified utilities with both regulated and unregulated assets). Furthermore, together the entities constitute a significant proportion of ATCO's revenue and assets.

Liquidity

We view ATCO's liquidity as "adequate." Sources less uses is positive with sufficient cushion, and sources over uses is greater than 1.2x over the next 12 months. In the event of a 15% drop in the company's EBITDA, we also expect there are sufficient liquidity sources to cover uses. In our view, the company has sound relationships with banks, generally high standing in credit markets, and generally prudent risk management.

Principal liquidity sources include:

- Cash FFO of about C$1.8 billion in 2015
- Undrawn committed facilities of about C$1.8 billion as of March 31, 2015, which matures between 2016 and 2019
- Cash on hand of C$649 million as of March 31, 2015

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Principal liquidity uses include:

- Forecast capital expenditures of C$1.8 billion in 2015
- Dividends of about C$300 million
- Debt and commercial paper maturity of about C$180 million in 2015

Outlook

The negative outlook reflects our view that the planned capital program that is forecast to occur in the context of a weaker Alberta operating environment could put pressure on financial metrics, which would cause us to remove our positive CRA modifier on the company.

Downside scenario

We could lower the rating on ATCO, based on the removal of our positive CRA modifier on the company, if we believe that the weaker Alberta operating environment coupled with the current forecast capital expenditure would cause FFO-to-debt to fall to or below 14% on a consistent basis. A weaker Alberta operating environment is characterized by sustained lower power prices in Alberta, a material negative change in the regulatory framework, a change in the company's financial policy, or a change in business strategy.

Upside scenario

We could revise the outlook back to stable should the company manage the capital program through the current operating environment with AFFO-to-debt returning to about 18% or better on a sustained basis.

Ratings Score Snapshot

Corporate Credit Rating: A/Negative/--

Business risk: Excellent

- Country risk: Very low
- Industry risk: Low
- Competitive position: Excellent

Financial risk: Significant

- Cash flow/Leverage: Significant

Anchor: a-

Modifiers

- Diversification: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Financial policy: Neutral (no impact)
- Management and governance: Strong (no impact)
- Comparable rating analysis: Positive (+1 notch)

Group credit profile: a

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Related Criteria And Research

Related Criteria

- Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Key Credit Factors For The Unregulated Power And Gas Industry, March 28, 2014
- Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Corporate Methodology, Nov. 19, 2013
- Corporate Criteria: Ratios and Adjustments, Nov. 19, 2013
- Group Rating Methodology, Nov. 19, 2013
- Methodology: Industry Risk, Nov. 19, 2013
- Country Risk Assessment Methodology and Assumptions, Nov. 19, 2013
- Methodology For Linking Short-Term And Long-Term Ratings For Corporate, Insurance, And Sovereign Issuers, May 7, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- Hybrid Capital Handbook: September 2008 Edition, - Sept. 15, 2008
- 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

Ratings List

Ratings Affirmed; Outlook Revised

	To	From
ATCO Ltd.		
Corporate Credit Rating	A/Negative/--	A/Stable/--
CU Inc.		
Canadian Utilities Ltd.		
Corporate Credit Rating	A/Negative/A-1	A/Stable/A-1

Ratings Affirmed

ATCO Ltd.	
Preferred Stock	
Global scale	BBB+
Canada scale	P-2(High)
CU Inc.	
Senior Unsecured	A
Preferred Stock	
Global scale	BBB+
Canada scale	P-2(High)
Commercial Paper	
Global scale	A-1
Canada scale	A-1(MID)

Canadian Utilities Ltd.

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Senior Unsecured	A
Preferred Stock	
Global scale	BBB+
Canada scale	P-2(High)
Preference Stock	
Global scale	BBB+
Canada scale	P-2(High)
Commercial Paper	
Global scale	A-1
Canada scale	A-1(MID)

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ATCO Ltd.

Primary Credit Analyst:
Andrew Ng, Toronto (416) 507-2545; andrew.ng@standardandpoors.com

Secondary Contact:
Stephen R Goltz, Toronto (416) 507-2592; stephen.goltz@standardandpoors.com

Research Assistant:
Siddharth Shah, Mumbai

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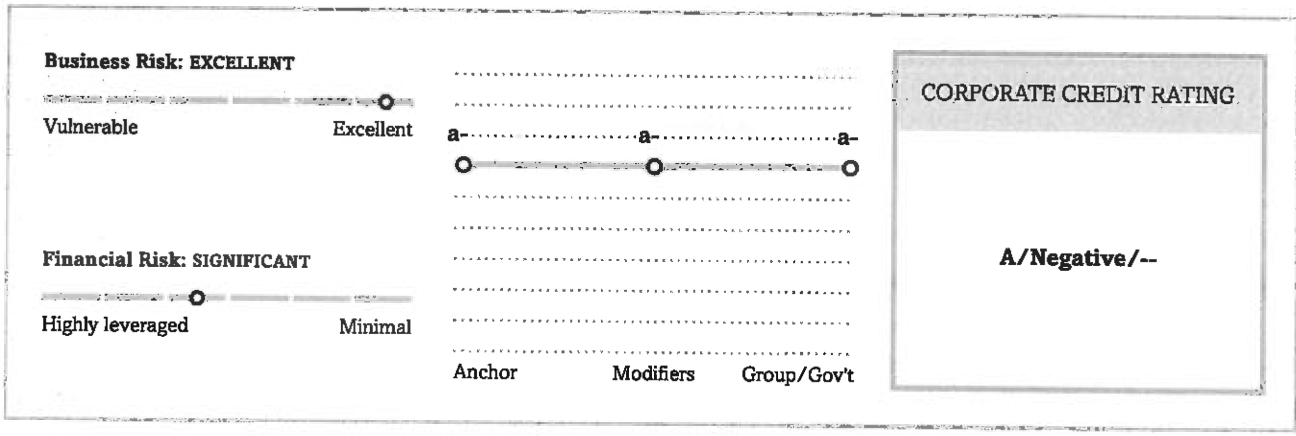
ATCO Ltd.



Rationale

Business Risk	Financial Risk
• Stable regulated utilities constituting the largest segment • Significant regulated growth prospects • Limited-but-improving geographic and regulatory diversity • Weakened operating environment in Alberta	• Negative free cash flow for the next several years • Downward pressure on credit metrics as a result of large capital programs over next several years

Outlook

The negative outlook on ATCO Ltd. reflects Standard & Poor's Ratings Services' view that the planned capital program that is forecast in the context of a weaker Alberta operating environment could put pressure on the company's financial metrics, which would cause us to remove our positive comparable rating analysis (CRA) modifier on the company.

Downside scenario

We could lower the rating on ATCO, based on the removal of our positive CRA modifier on the company, if we believe that the weaker Alberta operating environment coupled with the current forecast capital expenditure would cause funds from operations (FFO)-to-debt to fall to or below 14% on a consistent basis. A weaker Alberta operating environment is characterized by sustained lower power prices in Alberta, a material negative change in the regulatory framework, a change in the company's financial policy, or a change in business strategy.

Upside scenario

We could revise the outlook back to stable should the company manage its capital program through the current operating environment with adjusted FFO-to-debt returning to about 18% or better on a sustained basis.

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Standard & Poor's Base-Case Scenario

Assumptions

- Capital programs will be brought into service on time and on budget from 2015 to 2017, with about C$7 billion-C$8 billion
- The regulatory regime will be relatively stable and ATCO will not experience any material, adverse regulatory decisions
- The company will continue to earn its allowed returns on its various utility holdings

Key Metrics

	2014A	2015E	2016E
FFO to debt	15.3%	14%-15%	14%-15%
Debt to EBITDA	4.6x	About 4.7x	About 4.7x

Company Description

ATCO is a Canada-based company engaged in structures and logistics (manufacturing, logistics, and noise abatement), utilities (pipelines, natural gas, and electricity transmission and distribution), and energy (power generation, natural gas gathering, processing, storage, and liquids extraction). As a holding company it owns a 53.2% economic stake and controlling shareholder position in another holding company, Canadian Utilities Ltd. (CU Ltd.), which provided about 85% of ATCO's consolidated FFO in 2014. CU Ltd. itself owns 100% of CU Inc., a regulated utility in Alberta.

Business Risk

We continue to assess ATCO's business risk profile as "excellent." We believe CU Inc.'s Alberta-based regulated utilities will continue to generate stable cash flow, which we expect to increase to more than 70% of consolidated cash flow at the ATCO level in the next few years, anchoring the business risk profile. However, CU Inc. is predominantly exposed to a single regulator, the Alberta Utilities Commission (AUC), so ATCO does not benefit from meaningful regulatory diversity.

We expect the AUC to continue to operate within its legislative framework and set rates for utilities in Alberta without political interference. However, the outcome of AUC's latest decisions has a negative impact on ATCO's revenue and recovery of prudent capital spending contributing additional pressure on cash flow stability. These decisions included the generic cost of capital decision, in which equity thickness and return on equity were lowered by 100 basis points (bps) and 45 bps, respectively, and retroactively applied to previous years 2013 and 2014; as well as the utility asset disposition ruling that equity investors instead of ratepayers need to bear the risk of stranded assets.

We expect ATCO Power, which operates in an environment with "moderately high" industry risk, will contribute approximately 10%-15% of cash flows with some variability. ATCO Power's level of fleet contractedness of about 60% (based on generating capacity), strong counterparties, and amortizing project-financed nonrecourse debt in its independent power projects somewhat offset the higher industry risk. The fleet is concentrated in Alberta but has what

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we view as a good operational track record.

ATCO Structures and Logistics' cash flow is typically project-focused, so the company has near-term cash flow visibility. It has more variable long-term cash flow that is influenced by commodity pricing and the macroeconomic environment, which drive the need for this business' products and services. Cash flow from this segment accounts for about 5%-10% of consolidated cash flow.

S&P Base-Case Operating Scenario

- The company will continue to earn its allowed return on equity on its deemed capital structure
- ATCO will not experience any further material, adverse regulatory decisions
- There will be no material delays and cost overruns in the construction of major capital projects
- ATCO's capital programs total about C$7 million-C$8 billion from 2015 to 2017

Peer comparison

Table 1

ATCO Ltd. -- Peer Comparison

Industry Sector: Electric Utility

	ATCO Ltd.	Emera Inc.	AltaLink L.P.	FirstEnergy Corp.	Fortis Inc.
Rating as of July 17, 2015	A/Negative/--	BBB+/Stable/--	A-/Stable/--	BBB-/Stable/--	A-/Stable/--
	--Average of past three fiscal years--				
(Mil. C$)					
Revenues	4,425.0	2,416.9	556.4	16,052.8	4,367.3
EBITDA	1,769.2	888.2	408.2	4,474.6	1,502.8
Funds from operations (FFO)	1,253.3	637.7	305.7	3,316.0	980.7
Net income from continuing operations	404.3	300.5	162.0	470.6	375.3
Cash flow from operations	1,198.3	593.1	257.5	2,532.4	887.4
Capital expenditures	2,187.3	386.2	1,450.9	3,297.5	1,206.7
Free operating cash flow	(989.0)	206.9	(1,193.4)	(765.1)	(319.3)
Discretionary cash flow	(1,195.5)	3.0	(1,232.7)	(1,629.3)	(537.9)
Cash and short-term investments	154.6	33.3	2.3	33.6	38.0
Debt	7,301.5	4,575.4	2,826.0	24,727.7	10,227.1
Equity	5,098.7	2,613.5	1,865.4	13,635.1	6,273.2
Adjusted ratios					
EBITDA margin (%)	40.0	36.7	73.4	28.0	34.4
Return on capital (%)	9.8	8.1	6.7	5.9	5.9
EBITDA interest coverage (x)	4.3	4.0	4.0	3.2	3.0
FFO cash interest coverage (x)	5.2	4.7	4.3	4.3	3.3
Debt/EBITDA (x)	4.1	5.2	6.9	5.5	6.8
FFO/debt (%)	17.2	13.9	10.8	13.5	9.6
Cash flow from operations/debt (%)	16.4	13.0	9.1	10.3	8.7
Free operating cash flow/debt (%)	(13.5)	4.5	(42.2)	(3.0)	(3.1)

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Table 1

ATCO Ltd. -- Peer Comparison (cont.)					
Discretionary cash flow/debt (%)	(16.4)	0.1	(43.6)	(6.5)	(5.3)

Financial Risk

Our view of ATCO's financial risk profile is "significant," based on the medial volatility table, which reflects the combined "low" industry risk associated with regulated utilities with the supportive regulatory framework and unregulated power.

We expect ATCO will continue to generate stable cash flow from its regulated operations, which we believe is a key credit strength. The company has very large capital programs in the next few years and relies on the combination of internal generated funds and external debt to fund these expenditures. This places additional stress on credit metrics, especially the AFFO-to-debt ratio. We forecast the company's credit metrics will continue to deteriorate from current levels through to 2017, with AFFO-to-debt at the lower end of the "significant" range, at about 14% in 2015, and only marginally improving to about 15% in 2016. This continues the deterioration we've seen in the past couple of years with AFFO-to-debt of 15.3% in 2014 down from 18.2% in 2013. Despite the company spending largely on regulated rate-based expansion in the past few years, we do not foresee ATCO moving away from the medial table given its nonregulated holdings and planned investments.

S&P Base-Case Cash Flow And Capital Structure Scenario

Our base-case cash flow and capital structure scenario assumes the following:

- Totaled capital expenditure of about C$7 million-C$8 billion from 2015 to 2017
- Dividend payments of C$300 million annually
- FFO-to-debt of about 14% and 15% in 2015 and 2016, respectively

Financial summary

Table 2

ATCO Ltd. -- Financial Summary					
Industry Sector: Electric Utility					
	--Fiscal year ended Dec. 31--				
	2014	**2013**	**2012**	**2011**	**2010**
Rating history	A/Stable/--	A/Stable/--	A/Stable/--	A/Stable/--	A/Stable/--
(Mil. C$)					
Revenues	4,554.0	4,359.0	4,362.0	3,991.0	3,486.0
EBITDA	1,778.0	1,812.0	1,717.5	1,508.5	1,345.2
Funds from operations (FFO)	1,257.9	1,285.0	1,217.1	1,082.2	950.4
Net income from continuing operations	420.0	418.0	375.0	327.0	281.0
Cash flow from operations	1,129.9	1,357.0	1,108.1	1,137.2	963.4

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Table 2

ATCO Ltd. -- Financial Summary (cont.)					
Capital expenditures	2,123.0	2,296.0	2,143.0	1,415.0	863.0
Free operating cash flow	(993.1)	(939.0)	(1,034.9)	(277.8)	100.4
Discretionary cash flow	(1,215.6)	(1,141.0)	(1,229.9)	(465.3)	(71.6)
Cash and short-term investments	148.8	185.8	129.3	192.0	162.0
Debt	8,199.1	7,067.8	6,637.5	5,355.9	3,844.2
Equity	5,629.0	5,284.0	4,383.0	4,129.5	3,756.0
Adjusted ratios					
EBITDA margin (%)	39.0	41.6	39.4	37.8	38.6
Return on capital (%)	8.6	9.9	11.0	11.9	11.9
EBITDA interest coverage (x)	4.1	4.4	4.4	4.8	4.6
FFO cash int. cov. (x)	4.9	5.4	5.4	5.7	5.4
Debt/EBITDA (x)	4.6	3.9	3.9	3.6	2.9
FFO/debt (%)	15.3	18.2	18.3	20.2	24.7
Cash flow from operations/debt (%)	13.8	19.2	16.7	21.2	25.1
Free operating cash flow/debt (%)	(12.1)	(13.3)	(15.6)	(5.2)	2.6
Discretionary cash flow/debt (%)	(14.8)	(16.1)	(18.5)	(8.7)	(1.9)

Liquidity

We view ATCO's liquidity as "adequate." Sources less uses are positive with sufficient cushion, and sources over uses are greater than 1.2x over the next 12 months. In the event of a 15% drop in the company's EBITDA, we also expect there are sufficient liquidity sources to cover uses. In our view, the company has sound relationships with banks, generally high standing in credit markets, and generally prudent risk management.

Principal Liquidity Sources	Principal Liquidity Uses
• Cash FFO of about C$1.8 billion in 2015 • Undrawn committed facilities of about C$1.8 billion as of March 31, 2015, which mature between 2016 and 2019 • Cash on hand of C$649 million as of March 31, 2015	• Forecast capital expenditures of C$1.8 billion in 2015 • Dividends of about C$300 million • Debt and commercial paper maturity of about C$180 million in 2015

Debt maturities

ATCO has manageable long-term debt and capital lease maturities in the next three years, in our opinion. We believe the company maintains good access to capital markets to refinance its debt maturities and commercial paper.

Table 3

ATCO Ltd. -- Debt Maturities (Mil. C$)	
Year	**Amount**
2015	98
2016	86

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Table 3

ATCO Ltd. -- Debt Maturities (Mil. C$) (cont.)	
2017	165
2018	15
2019	1,136
After 2019	5,924
Total	7,424

Note: Does not include commercial paper maturity.

Covenant Analysis

We forecast the company to continue to have considerable headroom above a key covenant that restricts debt-to-capital below 75%.

Other Modifiers

We have applied a positive CRA modifier to the anchor score of 'a-'. Our use of a positive CRA modifier reflects our view of the company's ability to execute a long-term strategy that consistently delivers stable growth. Moreover, such growth has been in the context of conservative management with measured acquisition and growth strategies.

Group Influence

With the application of our group rating methodology, we assess the group credit profile to be equal to that of ATCO, at 'a'. Because we view CU Ltd. and CU Inc. to be "core" to the group, we have equalized our ratings on them with those on ATCO. CU Ltd. and CU Inc. are considered core to the ATCO group primarily because both entities are unlikely to be sold and have a strong long-term commitment of support from ATCO's senior management. In addition, both subsidiaries operate in lines of business integral to ATCO's group strategy (diversified utilities with both regulated and unregulated assets). Furthermore, together the entities constitute a significant proportion of ATCO's revenue and assets.

Ratings Score Snapshot

Corporate Credit Rating

A/Negative/--

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Low
- **Competitive position:** Excellent

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Financial risk: Significant

- **Cash flow/Leverage:** Significant

Anchor: a-

Modifiers

- **Diversification/Portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Strong (no impact)
- **Comparable rating analysis:** Positive (+1 notch)

Stand-alone credit profile : a

- **Group credit profile:** a
- **Entity status within group:** Core

Reconciliation

Table 4

Reconciliation Of ATCO Ltd. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. C$)

	--Fiscal year ended Dec. 31, 2014--								
ATCO Ltd. reported amounts									
	Debt	**Shareholders' equity**	**EBITDA**	**Operating income**	**Interest expense**	**EBITDA**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
Reported	7,388.0	4,470.0	1,887.0	1,326.0	300.0	1,887.0	1,550.0	254.0	2,199.0
Standard & Poor's adjustments									
Interest expense (reported)	N/A	N/A	N/A	N/A	N/A	(300.0)	N/A	N/A	N/A
Interest income (reported)	N/A	N/A	N/A	N/A	N/A	14.0	N/A	N/A	N/A
Current tax expense (reported)	N/A	N/A	N/A	N/A	N/A	(98.0)	N/A	N/A	N/A
Operating leases	124.1	N/A	43.0	9.8	9.8	33.2	33.2	N/A	N/A
Intermediate hybrids reported as equity	651.0	(651.0)	N/A	N/A	31.5	(31.5)	(31.5)	(31.5)	N/A
Postretirement benefit obligations/deferred compensation	333.8	N/A	4.0	4.0	16.0	(12.0)	N/A	N/A	N/A
Surplus cash	(446.3)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Capitalized interest	N/A	N/A	N/A	N/A	76.0	(76.0)	(76.0)	N/A	(76.0)

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Table 4

Reconciliation Of ATCO Ltd. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. C$) (cont.)									
Share-based compensation expense	N/A	N/A	4.0	N/A	N/A	4.0	N/A	N/A	N/A
Asset retirement obligations	148.5	N/A	N/A	N/A	5.0	(2.8)	(2.8)	N/A	N/A
Non-operating income (expense)	N/A	N/A	N/A	14.0	N/A	N/A	N/A	N/A	N/A
Reclassification of interest and dividend cash flows	N/A	N/A	N/A	N/A	N/A	N/A	(343.0)	N/A	N/A
Non-controlling Interest/Minority interest	N/A	1,810.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
EBITDA - gain/(loss) on disposals of PP&E	N/A	N/A	(160.0)	(160.0)	N/A	(160.0)	N/A	N/A	N/A
Total adjustments	811.1	1,159.0	(109.0)	(132.2)	138.3	(629.1)	(420.1)	(31.5)	(76.0)

Standard & Poor's adjusted amounts

	Debt	Equity	EBITDA	EBIT	Interest expense	Funds from operations	Cash flow from operations	Dividends paid	Capital expenditures
Adjusted	8,199.1	5,629.0	1,778.0	1,193.8	438.3	1,257.9	1,129.9	222.5	2,123.0

N/A--Not applicable. PPE&E--Property, plant, and equipment.

Related Criteria And Research

Related Criteria

- Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Key Credit Factors For The Unregulated Power And Gas Industry, March 28, 2014
- Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Corporate Methodology, Nov. 19, 2013
- Corporate Criteria: Ratios and Adjustments, Nov. 19, 2013
- Group Rating Methodology, Nov. 19, 2013
- Methodology: Industry Risk, Nov. 19, 2013
- Country Risk Assessment Methodology and Assumptions, Nov. 19, 2013
- Methodology For Linking Short-Term And Long-Term Ratings For Corporate, Insurance, And Sovereign Issuers, May 7, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- Hybrid Capital Handbook: September 2008 Edition, Sept. 15, 2008
- 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

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Business And Financial Risk Matrix

Business Risk Profile	Financial Risk Profile					
	Minimal	Modest	Intermediate	**Significant**	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	a-	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

Ratings Detail (As Of July 30, 2015)

ATCO Ltd.	
Corporate Credit Rating	A/Negative/--
Preferred Stock	
Canada National Scale Preferred Share	P-2(High)
Preferred Stock	BBB+
Corporate Credit Ratings History	
07-Jul-2015	A/Negative/--
07-Jan-2004	A/Stable/--
05-Mar-2003	A+/Watch Neg/--
Related Entities	
ATCO Gas Australia LP	
Issuer Credit Rating	A-/Negative/--
Senior Unsecured	A-
Canadian Utilities Ltd.	
Issuer Credit Rating	A/Negative/A-1
Commercial Paper	
Local Currency	A-1
Canada National Scale Commercial Paper	A-1(MID)
Preference Stock	
Canada National Scale Preferred Share	P-2(High)
Preference Stock	BBB+
Preferred Stock	
Canada National Scale Preferred Share	P-2(High)
Preferred Stock	BBB+
Senior Unsecured	A
CU Inc.	
Issuer Credit Rating	A/Negative/A-1
Commercial Paper	
Local Currency	A-1
Canada National Scale Commercial Paper	A-1(MID)
Preferred Stock	
Canada National Scale Preferred Share	P-2(High)
Preferred Stock	BBB+

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Ratings Detail (As Of July 30, 2015) (cont.)	
Senior Unsecured	A

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

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Rating Report
Report Date:
March 12, 2014
Previous Report
March 15, 2013

Enbridge Gas Distribution Inc.

Insight beyond the rating.

Rating

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable
Unsecured Debentures & Medium-Term Notes	A	Confirmed	Stable
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Confirmed	Stable

Analysts
Eric Eng, MBA
+1 416 597 7578
eeng@dbrs.com

Tom Li
+1 416 597 7378
tli@dbrs.com

James Jung, CFA, FRM, CMA
+1 416 597 7577
jjung@dbrs.com

The Company
Enbridge Gas Distribution Inc. (EGD) is a regulated natural gas distribution utility, serving over two million customers in the central, eastern and the Niagara Peninsula regions of Ontario. EGD also distributes natural gas to approximately 15,800 customers in northern New York State through a wholly owned subsidiary, St. Lawrence Gas Company, Inc. (approximately 0.6% of 2013 consolidated EBIT).
EGD is an indirect wholly owned subsidiary of Enbridge Inc. (rated A (low)).

Commercial Paper Limit
$700 million

Recent Actions
March 15, 2013
Confirmed

Ratings Update

DBRS has confirmed the ratings of Enbridge Gas Distribution Inc. (EGD or the Company) as listed above. The Company's ratings are based on its low-risk business profile, supported by a stable regulatory environment in Ontario and a strong franchise area with a large customer base. The confirmation factors in DBRS's expectation that the Company will continue to finance its free cash flow deficits to maintain its credit ratios within DBRS's "A" rating category.

EGD's business risk profile is indicative of an "A" rating, underpinned by the following factors: (1) EGD operates under a stable regulatory system. In 2013, following the five-year Incentive Regulation (IR) period, EGD operated under the Cost-of Service (COS) system. The move to COS methodology provided the Company with an opportunity to rebase and earn a higher return on equity (ROE) (8.93% compared with 8.39% in the IR period), while the deemed equity remained unchanged at 36%, which is relatively low compared with other jurisdictions. Natural gas supply costs continue to be passed through to EGD's customers. (2) EGD's franchise area, primarily the Greater Toronto Area (GTA), is viewed as one of the most economically strong service areas in Canada. In addition, the Company's large customer base of over two million should provide it with a critical mass to meet or exceed its efficiency factor during the next IR term (2014-2018). The Company filed an IR application for the 2014-2018 period in July 2013, and the decision by the Ontario Energy Board (OEB) is expected in Q2 2014. Should the OEB render an unfavourable decision to the extent that it may have a materially negative impact on the Company's future earnings and cash flow, a negative rating action could follow (although this will not likely be the case).

EGD's financial profile reflects an "A" rating, with all credit metrics remaining solidly within the current rating range. However, two concerns over the near to medium term are as follows: (1) Significant liquidity is required to finance EGD's volatile working capital (mostly gas inventory for winter distributions). EGD's liquidity is currently viewed as adequate to meet its operational needs given low natural gas prices. Should natural gas prices increase significantly, DBRS expects EGD to properly manage its liquidity to cope with that situation. (2) Large free cash flow deficits are expected over the next two years because of the $686.5 million GTA Expansion project. EGD's parent (Enbridge Inc.) is expected to continue providing financial support for EGD. DBRS expects EGD to finance its cash flow shortfalls while maintaining the debt leverage within the regulatory capital structure and all other credit metrics within the DBRS "A" rating range. This project has been approved by the OEB and should provide good earnings growth once it is in service, which is expected to occur by the end of 2015.

Rating Considerations

Strengths
(1) Stable regulatory framework
(2) Strong franchise with a large customer base
(3) Reasonable balance sheet/solid credit metrics

Challenges
(1) Weather-related volume risk
(2) Large capex program
(3) High dividend payout

Financial Information

Enbridge Gas Distribution Inc. (CA$ millions)	For the year ended December 31 2013	2012	2011	2010	2009
Net income before extra. Items	217	119	171	193	221
Cash flow from operations	524	472	473	467	504
Total debt in capital structure (1)	55.7%	55.5%	55.1%	58.7%	57.8%
EBIT gross interest coverage (times) (1)	2.60	2.05	2.29	2.62	2.87
Cash flow/Total debt (1)	16.4%	15.8%	16.0%	16.9%	18.7%
Total debt/EBITDA (times) (1)	4.75	4.91	4.68	4.15	3.85
Approved ROE	8.93%	8.39%	8.39%	8.39%	8.39%

(1) Excludes inter-company loans and/or inter-company dividend income and interest expense.
Note: Reported under U.S. GAAP except 2010 and 2009, which were under Canadian GAAP.

DBRS

Enbridge Gas Distribution Inc.

Report Date:
March 12, 2014

Rating Considerations Details

Strengths

(1) **Stable regulatory framework.** The regulatory framework in Ontario and the nature of the Company's natural gas distribution, transportation and storage operations , which are mostly regulated, have underpinned the Company's strong business risk profile. The Ontario regulatory regime provides the Company with the following benefits that support the "A" rating: (a) gas supply costs are passed through to customers, with quarterly adjustments to the rates; (b) the 2013 Settlement (under the COS framework) allowed EGD to rebase its rate base, to recover prudently incurred operating costs, and to earn a higher ROE than the 2008-2012 period; and (c) beyond 2013, the Company is expected to continue to operate under an IR framework (2014-2018), which affords the Company an opportunity to earn the allowed ROE through its operational efficiency.

(2) **Strong franchise with a large customer base.** EGD is the largest regulated natural gas distributor in Canada, serving over two million customers (2.065 million active customers at the end of 2013) in the central, eastern and Niagara Peninsula regions of Ontario. The Company's service area is viewed as economically strong, and its large customer base allows it to achieve operational efficiency. This is an important consideration for when the Company begins operating under the next IR term where the Company needs to achieve operational efficiency either equal to or better than the productivity factor in the IR-formula.

(3) **Reasonable balance sheet and solid credit metrics.** EGD maintains a reasonable balance sheet and credit metrics commensurate with the current ratings. EGD is committed to maintaining its capital structure within the regulatory approved level of 64% debt and 36% equity. The current debt leverage (55.7% at the end of 2013) provides the Company with some financial flexibility with respect to its future financing plan for the GTA project.

Challenges

(1) **Weather-related volume risk.** Weather risk remains significant as forecast volumes (based on the normalized weather) are built into the Company's base rates, while actual usage varies with actual weather. Therefore, colder-than-normal weather in a given year generally results in higher earnings, while the reverse is true for periods of warmer-than-normal weather. However, normalized weather is updated annually by incorporating the most recent weather trend, thus mitigating any significant sustained exposure to weather conditions.

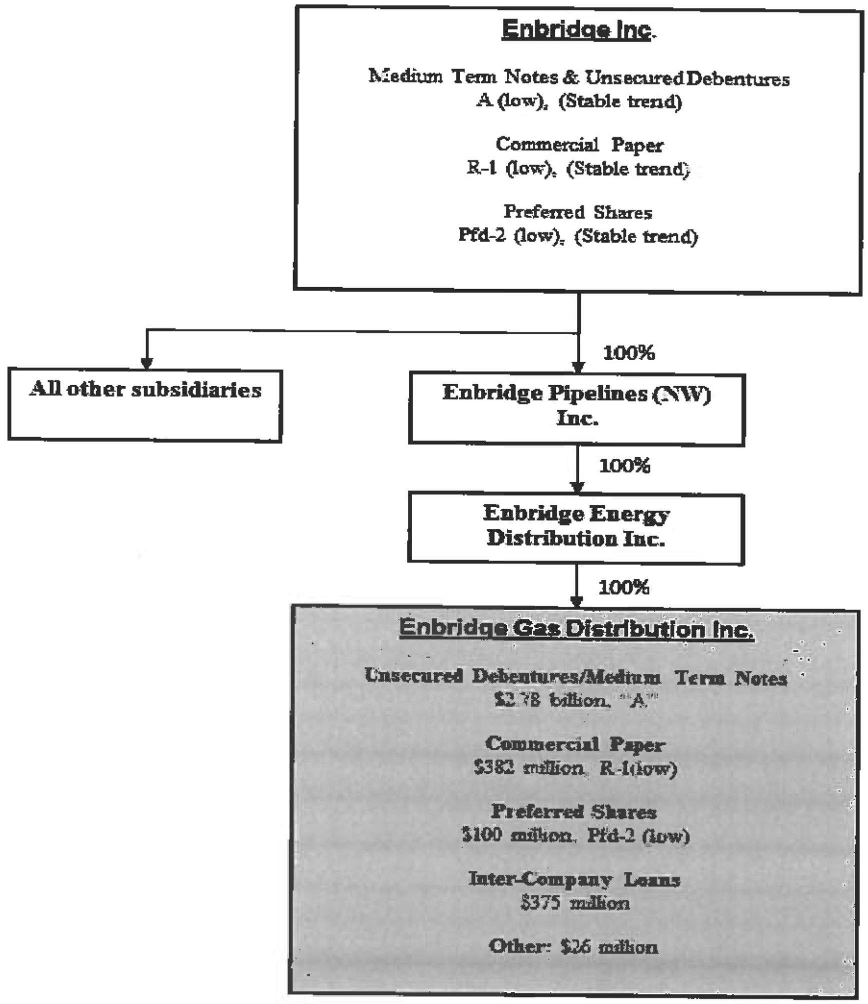
(2) **Large capex program.** The Company has a large capex program over the next two years, with $690 million estimated for 2014 and a larger amount expected for 2015. This large capex reflects the following factors: (a) high capex spending is required for system improvements and upgrades and (b) the financing of the 2014 portion of the GTA Expansion Project (see the GTA Project below). As a result, EGD is expected to generate large free cash flow deficits and will require external funds. DBRS expects the Company to maintain its debt leverage within the regulatory approved level and to maintain all other metrics within the DBRS "A" rating range, while carrying out its financing plan. DBRS also expects Enbridge Inc. to continue providing equity support for the Company in a timely fashion.

(3) **High dividend payout.** In general, EGD has a dividend payout ratio target of 90% to 100%, which DBRS views as high. Over the past five years, its dividend payout ratio, based on net income before extra items, has averaged around 116%. However, EGD's dividend payout is subject to maintaining the Company's capital structure in line with the regulatory approved level.

Enbridge Gas Distribution Inc.

Report Date:
March 12, 2014

Simplified Organizational Chart



Debt information as of December 31, 2013.

The Great Toronto Area Expansion Project (the GTA Project)

- The purpose of the GTA Project is to expand EGD's natural gas distribution system in the GTA to meet the demands of customer growth and to continue delivering safe and reliable natural gas to current and future customers.
- The proposed GTA project will consist of two segments of pipeline and related facilities to upgrade the existing system that delivers natural gas to several municipalities in Ontario.
- In January 2014, the OEB approved the project with the capital cost of $686.5 million.
- Construction is expected to start in late 2014, with completion targeted for the end of 2015.
- The Company is expected to fund this project with an appropriate mix of debt and equity to maintain its capital structure in line with the regulatory approved structure. DBRS expects the Company's parent to continue providing equity support for this project.
- During the construction, the Company's cash flow metrics are expected to weaken slightly from the 2013 level. However, once the project is fully in service, these metrics should return to the current level.

Enbridge Gas Distribution Inc.

Report Date:
March 12, 2014

Earnings and Outlook

Enbridge Gas Distribution Inc.	USGAAP	USGAAP	USGAAP	CGAAP	CGAAP
		For the year ended December 31			
(CA$ millions)	2013	2012	2011	2010	2009
Net gas distribution revenue	741	640	584	605	576
Gas transportation service revenue	328	345	421	390	449
Gas distribution margin	1,069	985	1,005	995	1,025
Other revenue (1)	99	113	103	108	108
Total revenue	1,168	1,098	1,108	1,103	1,133
EBITDA	672	609	630	666	699
EBIT	368	289	328	396	445
Earnings sharing	0	10	13	19	19
Intercompany dividend income	63	63	63	63	63
Interest expense (external)	(142)	(141)	(143)	(151)	(155)
Interest expense (intercompany)	(27)	(27)	(27)	(27)	(27)
Net income before extra. Items	217	119	171	193	221
Extra items	0	93	2	0	0
Reported net income	217	212	173	193	221

(1) Adjusted for $89 million recognition in regulatory asset related to other postretirement benefits in 2012.

Deemed equity (EGD)	36%	36%	36%	36%	36%
Approved ROE (EGD)	8.93%	8.39%	8.39%	8.39%	8.39%
Distribution rate base (CA$ millions)	4,162	4,011	3,957	3,838	3,794

2013 Summary

- **Overall:** Higher earnings (before extraordinary items) reflected higher gas distribution earnings in Ontario due to colder weather, customer growth and higher allowed ROE. This increase was partially offset by (1) the elimination of earnings sharing under the 2013 Settlement and (2) lower transportation revenues.
- EGD's earnings are mainly generated from gas distribution operations (approximately 63% of 2013 total revenue) and gas transportation operations (28% of 2013 total revenue), with the storage business largely contributing the remaining earnings percentage.
- Most of the gas distribution earnings are generated by the Company's Ontario operations; a small portion (about 0.6% of EBIT) is contributed by its wholly owned subsidiary, St. Lawrence Gas Company, Inc. (SLG), a natural gas distributor in New York State.
- The decline of transportation revenues over the past three years reflected an eroding customer base caused by customer switch. By the end of 2013, the number of active customers was 251,434 (versus 364,027 in 2011).
- The storage business includes regulated and unregulated facilities, with the latter accounting for approximately 2.1% of EGD's consolidated EBIT in 2013.
- Beside weather impact, earnings in regulated operations are mainly driven by rate base growth, approved ROE (which was higher in 2013), and the Company's operational efficiency during the IR period.
- The earnings sharing was no longer in effect in 2013 in accordance with the 2013 Settlement. During the 2008-2012 term, the sharing mechanism represented EGD's 50% share of actual ROE (excluding the effect of weather) in excess of 100 basis points above the allowed ROE.
- Dividend income represents the cash income from EGD's $825 million investment in its affiliate (IPL System Inc.), the holder of the Company's $375 million inter-company loan outstanding at December 31, 2013. The interest expense on this loan was $27 million in 2013.

2014 Outlook

- The earnings outlook for 2014 is expected to be positive, given the cold weather conditions in Q1 2014. In the absence of an adverse regulatory decision on the Company's IR application for 2014-2018, customer growth is expected to continue to have a positive impact on EGD's 2014 earnings. EGD's ability to achieve a production efficiency equal to or better than the productivity factor in the IR-formula (which has yet to be determined by the OEB) is critical to attaining the approved ROE.
- Should the GTA Project be brought in service on time (i.e., the end of 2015) and within the approved budget, earnings beyond 2015 are expected to increase meaningfully.

DBRS

Enbridge Gas Distribution Inc.

Report Date:
March 12, 2014

Financial Profile

Enbridge Gas Distribution Inc.	USGAAP	USGAAP	USGAAP	CGAAP	CGAAP
	For the year ended December 31				
(CA$ millions)	**2013**	**2012**	**2011**	**2010**	**2009**
Net income before extra. items	217	119	171	193	221
Depreciation & amortization	304	320	302	270	254
Deferred income taxes/Other	3	33	0	4	29
Cash flow from operations	524	472	473	467	504
Dividends paid	(202)	(208)	(220)	(210)	(185)
Capex	(553)	(452)	(448)	(365)	(370)
Free cash flow before WC	(231)	(188)	(195)	(108)	(51)
Changes in working capital (WC)	(86)	71	15	45	467
Net free cash flow	(317)	(117)	(180)	(63)	416
Acquisitions	0	0	0	0	0
Assets sales/Divestitures	0	72	0	0	0
Net changes in equity	150	0	0	0	0
Net changes in debt	192	38	164	58	(469)
Other (*)	16	1	12	(2)	(15)
Change in cash	41	(6)	(4)	(7)	(68)
Total external debt	3,192	2,988	2,950	2,937	2,766
Inter-company debt	375	375	375	375	375
Total debt/Capital (1)	55.7%	55.5%	55.1%	58.7%	57.8%
EBIT interest coverage (times) (1)	2.60	2.05	2.29	2.62	2.87
Cash flow/Total debt (1)	16.4%	15.8%	16.0%	16.9%	18.7%
Dividends/Cash flow	38.5%	44.1%	46.5%	45.0%	36.7%
Dividend payout ratio	93.1%	174.8%	128.7%	108.8%	83.7%

(1) Excludes inter-company loans and/or inter-company dividend income and interest expense.
(*) Adjusted for $89 million recognition in regulatory asset related to other postretirement benefits in 2012.

2013 Summary

- EGD maintained a reasonable financial profile for the "A" rating category in 2013, with all credit metrics either remaining stable or improving slightly from the prior year.
- A large cash flow deficit was generated in 2013 mainly because of an increase in capex, which can largely be attributed to higher spending on improvements and upgrades to the distribution system and customer growth projects (including the Franklin County Expansion Project (the Franklin Project) in New York State).
- The dividend policy remained unchanged from previous years, with the payout ratio target of 90% to 100%, subject to EGD's regulatory approved capital structure.
- The 2013 free cash flow deficit was mainly financed with a mix of debt and equity issuance. The issuance of equity was to maintain the capital structure within the regulatory structure (36% equity in 2013).

Note: In 2012, EGD sold its 99.9% partnership interest in Project Amherstburg (a power project) to Enbridge Income Fund (an affiliated entity) for $72 million. The cash proceeds were used to finance a portion of the Company's cash flow deficit that year.

2014 Outlook

- Capex for 2014 is estimated to be approximately $690 million for capital projects and maintenance. This amount is much higher than the past three-year average of $484 million. This increase largely reflects the 2014 portion of capex spending on the GTA project.
- As a result, the Company is expected to generate a large free cash flow deficit in 2014. DBRS expects (1) EGD to remain prudent in its financing of cash shortfalls and (2) the Company's parent to continue injecting equity into EGD, as it has in the past, to maintain the Company's capital structure within the regulatory approved level and within DBRS's "A" rating guidelines for a gas distribution company.

Enbridge Gas Distribution Inc.

Report Date:
March 12, 2014

Liquidity and Long-Term Debt Maturities

Bank Lines/Liquidity

Credit Facilities				As at Dec. 31, 2013
(CA$ millions)	**Total Facilities**	**Drawn**	**Available**	**Maturity**
Committed line of credit	700	370	330	2015
Uncommitted line of credit*	13	12	1	2019
Total	713	382	331	

* The uncommitted line of credit is at St. Lawrence Gas Company, Inc.

- EGD requires relatively high liquidity to support its volatile and seasonal working capital needs, which are heavily influenced by natural gas prices.
- The Company has a commercial paper program of $700 million, which is fully backed by the $700 million, 364-day revolving unsecured committed credit facility, maturing in August 2015.
- DBRS views EGD's current liquidity as sufficient to finance its working capital requirements. However, a combination of cold weather and high gas prices could exhaust the Company's available liquidity, although this scenario is unlikely, given the current low gas price environment.

Debt	As at Dec. 31, 2013
(CA$ million)	
Commercial paper	370
Other ST borowings	23
LT debt	2,399
LT debt mature in one year	400
Total	**3,192**

Long-Term Debt Maturity

Long-Term Debt Maturity Schedule	2014	2015	2016	2017	2018	Thereafter	Total
(CA$ million)							
As at Dec. 31, 2013 (CA$ millions)	400	1	2	201	2	2,193	2,799

- Given the Company's strong credit profile, the refinancing risk for the $400 million in medium-term notes due in 2014 remains manageable.
- EGD is subject to an EBIT-interest covenant of two times, based on EBIT for 12 consecutive months and annual pro forma interest requirements for all debt with a maturity term longer than 18 months.
  - The covenant does not apply to debt issuances for debt refinancing.
  - The Company was in compliance with the test at the end of 2013.

Inter-Company Debt

- As of December 31, 2013, EGD owned $825 million of Class D, non-voting redeemable, retractable preferred shares of IPL System Inc. (IPL), which is 100% owned by Enbridge Inc.
- The Company owes IPL $375 million in loans, which is deeply subordinated to the debentures and medium-term notes. EGD is able to defer interest payments on the loans for up to five years, and the deferred interest can be paid either by cash or by non-retractable preferred shares of the Company.
- DBRS excludes this debt from its calculation of the Company's capital structure.

Enbridge Gas Distribution Inc.

Report Date:
March 12, 2014

Regulation

Regulatory Overview

The OEB regulates EGD's gas storage, transmission and distribution businesses. Consumers in Ontario have been able to choose their natural gas supplier since 1985. The gas purchase cost is passed on to customers through quarterly adjustments; as a result, the Company's distribution margin is not affected by the gas purchase cost, subject to variances between total natural gas distributed by the Company and the amount of natural gas billed or billable to customers.

Gas Distribution: Ontario

- In 2013, the Company operated under the COS methodology pursuant to the 2013 Settlement. The Company retained the previous deemed equity level (36%). The allowed ROE was 8.93% (versus 8.39% in 2012). The earning sharing mechanism established under the 2008-2012 IR framework did not apply in the 2013 Settlement.
- The 2013 Settlement gave EGD the right to recover other post-retirement benefits (OPEB) costs of $89 million over a 20-year period, commencing 2013. It also provided for OPEB and pension costs determined on an accrued basis, to be recovered in rates.
- In July 2013, the Company filed an application for setting rates through a customized IR mechanism for the 2014-2018 period. A regulatory decision on the Company's application is expected in Q2 2014.
- DBRS does not expect the decision to have any changes that could have a negatively material impact on the Company's earnings and cash flows.

Gas Storage: Ontario

- EGD's gas storage business is semi-regulated. The OEB does not regulate the prices of storage services to customers outside the Company's franchise area or the prices of storage services to new customers (since November 2006) within the franchise area. Existing customers within the Company's franchise area continue to be charged at cost-based rates.

Transportation: National Energy Board (NEB)

- TransCanada Pipelines Limited (TransCanada) transports approximately 60% (7.4 billion cubic metres) of the annual natural gas requirements of EGD's customers; the remainder is obtained through contracts with Alliance Pipeline Canada, Alliance Pipeline U.S. and Vector Pipeline.
- The Company has Firm Transportation (FT) contracts with TransCanada for a portion of the requirement. Effective July 2013, the NEB approved new tolls on the FT service for TransCanada. Under the new tolls, the Company is required to pay TransCanada the demand component regardless of the volume transported.
- Transportation costs are passed through to customers.

Gas Distribution: New York

- The Company owns SLG, which provides natural gas distribution services to 15,800 customers in New York State.
- SLG is regulated by the New York State Public Service Commission under COS and is viewed as relatively stable.
- The approved ROE for 2013 was 10.5% (also 10.5% in 2012) on a deemed equity of 50% (also 50% in 2012). Any earnings above 11% will be shared equally with customers. SLG has had no earnings sharing since 2010 and will continue to operate under the existing COS agreement in 2014.
- SLG has no exposure to natural gas price risk, with gas supply costs being adjusted annually.
- SLG started construction in August 2012, following the July 2012 regulatory approval of the Franklin Project. The total capital cost over the five-year period is estimated to be USD 45 million. SLG is estimated to have spent approximately USD 38 million by the end of 2013. The Franklin Project is expected to add 4,400 potential customers to the system.

DBRS

Enbridge Gas Distribution Inc.

Report Date:
March 12, 2014

Enbridge Gas Distribution Inc.

Balance Sheet (US GAAP)

(CA$ millions)	Dec. 31 2013	Dec. 31 2012	Dec. 31 2011		Dec. 31 2013	Dec. 31 2012	Dec. 31 2011
Assets				**Liabilities & Equity**			
Cash & equivalents	44	3	6	S.T. borrowings	393	601	563
Accounts receivable	341	324	401	Current portion LTD	400	0	0
Inventories	382	341	380	Accounts payable	46	59	78
Others	365	281	265	Deferred tax	0	0	2
				Others	723	671	638
Total Current Assets	**1,132**	**949**	**1,052**	**Total Current Liabilities**	**1,562**	**1,331**	**1,281**
Net fixed assets	5,869	5,532	5,336	Long-term debt (LTD)	2,399	2,387	2,387
Future income tax assets	0	0	0	Deferred income taxes	395	362	304
Goodwill & intangibles	174	177	170	Loan from affiliate	375	375	375
Investments in affiliates	825	825	825	Other L.T. liabilities	1,026	1,094	1,025
Deferred and others	379	432	365	Preferred shares	100	100	100
				Shareholders equity	2,522	2,266	2,276
Total Assets	**8,379**	**7,915**	**7,748**	**Total Liab. & SE**	**8,379**	**7,915**	**7,748**

	USGAAP	USGAAP	USGAAP	CGAAP	CGAAP
Balance Sheet &		**For the year ended December 31**			
Liquidity & Capital Ratios	**2013**	**2012**	**2011**	**2010**	**2009**
Current ratio (times)	0.72	0.71	0.82	0.90	0.61
Total debt in capital structure	58.4%	58.4%	58.1%	61.8%	60.9%
Cash flow/Total debt (*)	14.6%	14.0%	14.2%	14.9%	16.4%
Cash flow/Capex (times)	0.95	1.04	1.06	1.28	1.36
(Cash flow - Dividends)/Capex (times)	0.58	0.58	0.56	0.70	0.86
Dividend payout ratio	93.1%	174.8%	128.7%	108.8%	83.7%
Dividends/Cash flow	38.5%	44.1%	46.5%	45.0%	36.7%
(*) debt includes inter-company debt					
Profitability Ratios					
EBITDA margin	57.5%	55.5%	56.9%	60.4%	61.7%
EBIT margin	31.5%	26.3%	29.6%	35.9%	39.3%
Profit margin	18.6%	10.8%	15.4%	17.5%	19.5%
Return on equity	8.7%	5.0%	N/A	9.9%	11.3%
Return on capital	5.9%	4.4%	N/A	6.3%	6.6%
Allowed ROE (EGD)	8.93%	8.39%	8.39%	8.39%	8.39%
Allowed ROE (St. Lawrence)	10.50%	10.5%	10.5%		
Excluding Inter-company Debt, Inter-company Dividend Income and Interest Expense					
Cash flow/Debt	16.4%	15.8%	16.0%	16.9%	18.7%
Total debt/Capital (1)	55.7%	55.5%	55.1%	58.7%	57.8%
EBITDA gross interest coverage (times)	4.73	4.32	4.41	4.41	4.51
EBIT gross interest coverage (times)	2.60	2.05	2.29	2.62	2.87
Debt/EBITDA (times)	4.75	4.91	4.68	4.15	3.85

(1) Includes operating leases.

Enbridge Gas Distribution Inc.

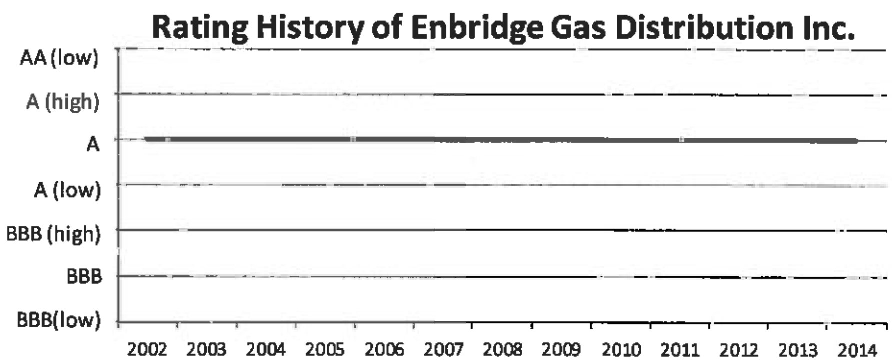
Report Date:
March 12, 2014

Rating

Debt Rated	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable
Unsecured Debentures & Medium-Term Notes	A	Confirmed	Stable
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Confirmed	Stable

Rating History

Debt Rated	Current	2013	2012	2011	2010	2009
Issuer Rating	A	A	A	NR	NR	NR
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Unsecured Debentures & Medium-Term Notes	A	A	A	A	A	A
Cum. & Cum. Redeemable Convertible Preferred Shares	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)



Note:
All figures are in Canadian dollars unless otherwise noted.

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Rating Report

FortisAlberta Inc.

Eric Eng
+1 416 597 7378
eeng@dbrs.com

Chris Gifford
+1 416 597 7398
cgifford@dbrs.com

Tom Li
+1 416 597 7338
tli@dbrs.com

DBRS
Insight beyond the rating.

Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A (low)	Confirmed/Trend Changed	Stable
Senior Unsecured Debt	A (low)	Confirmed/Trend Changed	Stable

Rating Update

On December 10, 2015, DBRS Limited (DBRS) confirmed the Issuer Rating and Senior Unsecured Debt rating of FortisAlberta Inc. (FortisAlberta or the Company) at A (low). The trends were changed to Stable from Positive. The confirmations reflect the Company's strong credit metrics and its low-risk business profile as a regulated distributor.

The change in trends reflects DBRS's negative view of the regulatory framework in Alberta regarding the Alberta Utilities Commission's (AUC or the Commission) decision on the Generic Cost of Capital (GCOC) and the decision of the Court of Appeal of Alberta to reject the Company's appeal on the Commission's 2013 decision on the Utilities Assets Disposition (UAD).

In March 2015, the Commission issued a decision on the GCOC and lowered the Company's return on equity (ROE) to 8.30% from 8.75% and the deemed equity to 40% from 41%. The decision took effect retroactively to 2013 and 2014. Although, the lower ROE and deemed equity only apply to the portion of based rates that are funded by revenue provided by mechanisms separate from the formula and should not have a material impact on the Company's overall cash flow, it was viewed as modestly credit negative since Alberta now has one of the lowest ROEs compared with other Canadian jurisdictions.

In September 2015, the Court of Appeal of Alberta denied the appeal brought by five utilities in Alberta (including FortisAlberta) regarding the Commission's' decision on the UAD. In 2013, the Commission issued a decision concluding that the shareholders of utilities, not the ratepayers, will bear the costs of stranded assets, which are assets that become incapable of being used to provide services to ratepayers due to some extraordinary event. Stranded assets would have to be removed from the rate base. DBRS continues to view potential UAD events as being low probability but with high impact.

DBRS notes that while these two above decisions are modestly negative to the credit profile of the Alberta utilities, the potential impact is not sufficient to warrant a negative rating action on the utilities in the province. That said, a Positive trend is no longer appropriate within the context of DBRS's view of the regulatory framework in Alberta. Further unfavourable regulatory decisions in the future could warrant negative rating actions for this and other Alberta-based regulated utilities.

The Company's A (low) rating continues to be supported by its low business risk and growing and relatively predictable cash flow from its regulated distribution operations. In addition, the new regulatory capital structure of 40% equity is still consistent with DBRS's "A" rating category as it still provides a strong cushion for the indebtedness in the capital structure.

Financial Information

	9 mos. September 30		12 mos. Sept. 30	For the year ended December 31st			
(CA$ millions) (US GAAP)	2015	2014	2015	2014	2013	2012	2011
EBIT-to-gross interest (x) 1	2.80	2.28	2.56	2.18	2.18	2.33	2.05
Cash flow-to-total debt 1	18.8%	15.6%	17.6%	17.0%	15.5%	16.2%	15.9%
Total debt-to-capital 1	57.3%	59.7%	57.3%	56.7%	57.6%	57.9%	57.3%
Net income before extra. items	109	78	133	102	94	96	73
Cash flow from operations	239	206	303	269	235	219	198

1 Includes operating leases.

Issuer Description

FortisAlberta is a regulated electricity distribution company with approximately 530,000 customers who account for more than 60% of the Alberta distribution grid. It is a wholly owned indirect subsidiary of Fortis Inc. FortisAlberta's franchise region is located in central and southern Alberta in the suburbs surrounding Edmonton, Calgary, Red Deer, Lethbridge and Medicine Hat.

Rating Considerations

Strengths

1. Low business risk

FortisAlberta's low business risk is supported by the following factors: (a) the Company is a regulated electric distributor, with no exposure to commodity price risk; (b) the regulatory system in Alberta under the Performance Based Regulation (PBR) framework (January 2013 through 2017) is viewed as reasonable, providing the opportunity for the Company to earn a return above the allowed ROE; (c) the Company has a sizable customer base to provide good scale to better achieve the productivity factor set in the PBR formula; and (d) the risk of actual operating costs exceeding the forecasted amount under the cost of service methodology is eliminated.

2. Good franchise area

FortisAlberta operates in good franchise areas, which have seen solid customer growth over the past ten years. Until 2015, economic growth in Alberta was consistently above the national average as a result of good performance in the energy sector over the past few years. This strong growth translated to a significant increase in the Company's rate base. The estimated rate base at mid-point 2015 was approximately $2.7 billion, versus $500 million in 2002.

3. Strong credit metrics

The Company has maintained consistently strong credit metrics that are consistent with the current rating. The Company's financing strategy going forward is to maintain the debt leverage within the regulatory capital structure (60% debt and 40% equity). Despite cash flow deficits expected over the medium term, this financing strategy and expected future cash flows should continue to support the Company's credit metrics to be consistent with the current rating.

Challenges

1. Large capital expenditure program

The Company is in the midst of a major capital expenditure (capex) program necessary to meet the rapid growth in population and power demand in its service territories. Approximately $400 million (before customer contributions) in capital spending is estimated for 2016. This is expected to continue to result in free cash flow deficits that will require external funds.

2. Shifting quality of the regulatory regime

Although FortisAlberta operates under a reasonable regulatory regime, the 2013 AUC decision that the utility shareholders will bear the costs of UAD was viewed as negative to the credit profile of utilities in Alberta. The UAD decision has increased the regulatory risk in Alberta as it would deny a utility the chance to recover past investments that had been viewed to be prudent by the regulator. In September 2015, the Court of Appeal of Alberta denied the utilities' appeal. In addition, DBRS views that the decision on the GCOC in March 2015 was negative as it reduced ROEs and deemed equity for utilities in the province.

3. Inflation/cost management risk

Under the PBR framework, an inflation factor and a productivity factor are included in the formula used to calculate the annual change in rates for distribution companies, which increases cost-cutting pressure on utilities. The Company faces the risk that it could experience inflationary increases in excess of the inflation factor set by the formula (see Regulation section). In addition, if the Company's actual productivity factor is lower than the productivity factor set by the regulator in the formula, earnings and cash flow could be negatively affected. This factor is critical in DBRS's credit review of FortisAlberta, since it places more pressure on cost efficiency for the Company.

Earnings and Outlook

Consolidated Income Statement (US GAAP)

(CA$ millions)	9 mos. September 30		12 mos. Sept. 30	For the year ended December 31st			
	2015	2014	2015	2014	2013	2012	2011
EBITDA	291	258	376	342	314	291	262
EBIT	166	135	209	178	165	158	128
Gross interest expense	59	59	82	82	76	68	62
Pre-tax income	108	77	132	101	95	96	73
Income tax	(1)	(1)	(1)	(1)	1	0	1
Net income before extra. items	109	78	133	102	94	96	73
Reported net income	109	78	133	102	94	96	74
Return on avg. common equity	11.6%	9.0%	10.8%	8.8%	8.9%	10.1%	8.4%
Regulated rate base *	-	-	2,698	2,501	2,287	2,003	1,767
Regulated deemed equity	40.0%	40.0%	40.0%	40%	40%	41%	41%
Regulated allowed ROE	8.30%	8.30%	8.30%	8.30%	8.30%	8.75%	8.75%

* Forecatsed for mid-year 2015.

Overall

- FortisAlberta's earnings have been growing, reflecting increases in the rate base associated with continued investment in energy infrastructure and customer growth.

2014 Summary

- Net income in 2014: Net income increased meaningfully over 2013 largely because of (1) rate base growth associated with continued investment in infrastructure, (2) growth in the number of customers and (3) income tax recovery.

2015 to Date Summary

- Net income was positively supported by higher revenues compared with the same period in 2014. Higher revenues reflected the approved I-X (inflation less productivity factor) increase of 1.49% and estimated capital tracker revenue based on the 2015 capital tracker and the 2015 GCOC decisions.
- In September 2015, capital tracker revenue of $17.4 million was approved for 2013 ($14.6 million already collected in 2013) on an actual basis, capital tracker revenue of $42.2 million was approved on a forecast basis for 2014 ($29.2 million already collected in 2014) and $62.2 million was approved on a forecast basis for 2015. The Company expects to collect $62.0 million in 2015.

2016 Outlook

- DBRS expects the Company's earnings to continue to grow over the medium term as a result of (1) growth in the rate base underpinned by large capital investments to facilitate customer growth and economic expansion in the Company's service area and (2) the Company is expected to maintain effective cost control under the PBR framework, as it benefits from a sizable customer base.
- However, the following factors could affect earnings growth in 2016 and over the PBR period: (1) if inflationary increases in excess of the inflation factor set by the regulator in the formula and (2) if the Company does not achieve the productivity factor set by the regulator over the PBR term.

Financial Profile

Consolidated Cash Flow Statement (US GAAP)

(CA$ millions)	9 mos. September 30		12 mos. Sept. 30	For the year ended December 31st			
	2015	2014	2015	2014	2013	2012	2011
Net income before extra. items	109	78	133	102	94	96	73
Depreciation & amortization	126	123	167	165	151	134	135
Deferred income taxes/Other	5	5	2	2	(10)	(11)	(10)
Cash flow from operations	239	206	303	269	235	219	198
Dividends	(45)	(41)	(59)	(55)	(50)	(45)	(40)
Capex	(282)	(217)	(372)	(307)	(400)	(403)	(367)
Free cash flow before WC	(88)	(53)	(128)	(93)	(215)	(229)	(209)
Changes in working capital	(53)	(2)	(73)	(21)	(99)	182	25
Net free cash flow	(141)	(54)	(201)	(114)	(314)	(47)	(184)
Acquisitions (Divestitures)	1	1	2	2	1	2	3
Net changes in equity	10	35	15	40	95	-	55
Net changes in debt	130	249	(47)	72	173	89	126
Other/Adjustments by DBRS	(0)	0	(0)	1	(0)	0	1
Change in cash	0	231	(231)	(0)	(44)	44	(0)
Total debt	1,688	1,734	1,688	1,557	1,484	1,309	1,219
Total debt-to-capital 1	57.3%	59.7%	57.3%	56.7%	57.6%	57.9%	57.3%
Cash flow-to-total debt 1	18.6%	15.6%	17.6%	17.0%	15.5%	16.2%	15.9%
EBIT-to-gross interest (x) 1	2.80	2.28	2.56	2.18	2.13	2.33	2.05
Total debt/EBITDA (x)	5.80	6.73	4.50	4.55	4.72	4.50	4.66
Capex/Depreciation (x)	2.24	1.76	2.22	1.86	2.64	3.01	2.72
Dividend payout ratio	41.4%	52.9%	44.2%	53.7%	53.3%	46.8%	55.1%

1 Includes operating leases.

Summary

- ***Overall:*** FortisAlberta has maintained a solid financial profile, supported by increasing cash flow, as the rate base continued to grow, and a prudent financing plan. As a result, credit metrics have been consistent with the current rating.
- Capex have been relatively higher than a normal electric utility, reflecting the investment requirement to support the energy infrastructure in Alberta and strong customer growth.
- As a result, the Company has consistently generated free cash flow deficits, which have been financed to maintain the debt in the capital structure below 60%, consistent with the regulatory debt-to-capital structures of 60% in 2014 and 2015.

Outlook

- Gross capex (before customer contributions) for 2015 is estimated to be approximately $400 million. The dividend payout is expected to be consistent with the Company's historical growth. As a result, large free cash flow deficits are expected to persist.
- However, Fortis Inc. (the parent) is expected to continue to support FortisAlberta with equity injections to maintain the Company's capital structure in line with the regulatory capital structure.
- DBRS also expects other key metrics to remain stable, as incremental cash flow should be generated consistently with the growth of the rate base.

Liquidity and Long-Term Debt Maturities

Credit Facilities as at September 30, 2015

(CA$ millions)	Committed	Drawn	LC	Available	Expiry
Unsecured committed credit facility	250.0	0.0	0.4	249.6	Aug-2020
Total	**250.0**	**0.0**	**0.4**	**249.6**	

Liquidity

- FortisAlberta's credit liquidity remains strong, with most of its $250 million credit facility being available to finance the Company's short-term operating needs.
- Drawings under the committed credit facility are available by way of prime loans, bankers' acceptances and letters of credit.
- As at September 30, 2015, there were no drawings under the committed credit facility and $0.4 million outstanding in letters of credit.

Long-Term Debt Maturities

As at September 30, 2015

(CA$ millions)	2015	2016	2017	2018	2019	Thereafter	Total
Long term debt	-	-	-	-	-	1,684	1,684
Total	**-**	**-**	**-**	**-**	**-**	**1,684**	**1,684**
% of total	0%	0%	0%	0%	0%	100%	100%

- The Company's near-term refinancing risk remains minimal, as refinance of long-term debt in 2014 has been completed, and no long-term debt is due within the 2015–2019 period.
- In September 2015, the Company issued $150 million senior unsecured debentures maturing in 2045. The proceeds of the issuances were used to to repay existing indebtedness incurred under the committed credit facility to finance capex and for general corporate purposes.

Regulation

The 2013–2017 PBR Period

- As of January 1, 2013, FortisAlberta is regulated under the PBR for a five-year term. The PBR model of rate-making employs a formula to determine customer rates on an annual basis. The customer, or base, rates for each class were derived from the 2012 approved revenue requirement. Base rates are adjusted annually by a PBR formula approved by the AUC.
- Under the PBR model, customer rates are determined by applying a multiplier, equivalent to an inflation factor (I) less a productivity factor (X), to the prior year's rates. Other components of the formula also include: (1) flow-through items to be collected, or refunded, annually (Y factor); (2) capex that are not recovered through the formula (I-X) and qualify as a capital tracker (K factor); and (3) exogenous costs outside of the control of the utility (Z factor).
- In September 2015, the Company filed its 2016 Annual Rates Application. The rates and riders, proposed to be effective on an interim basis for January 1, 2016, include an increase of 6.2% to the distribution component of customer rates. The decision is expected in the fourth quarter of 2015.

Capital Tracker

In December 2013, AUC issued Decision 2013-435 to provide additional guidance regarding capital trackers, which includes three criteria in assessing requested capital trackers. The guidance provided some clarification for the capital tracker mechanism as follows:

1. The project must be outside the normal course of the Company's ongoing operations.
2. Ordinarily, the project must be for replacement of existing capital assets, or undertaking the project must be required by an external party.
3. The project must have a material effect on the Company's finances.

- In May 2014, the Company submitted a combined application for the 2013, 2014 and 2015 capital trackers as prescribed by the AUC, seeking capital tracker revenue of $23.2 million, $48.1 million and $68.9 million, respectively.
- In September 2015, The AUC approved the Company's compliance filing with regards to the 2015 capital tracker decision allowing for 75%, 88% and 90% of the then-applied-for capital tracker revenues for 2013, 2014 and 2015, respectively. However, capital tracker revenues in 2014 and 2015 are subject to changes based on the true-up to capex.

Regulation (CONTINUED)

- Also, in May 2015, the Company submitted a capital tracker application seeking: (1) a reduction to the 2014 capital tracker revenue of $7.2 million to reflect actual capex; (2) capital tracker revenue for 2016 and 2017 of $71.5 million and $89.9 million, respectively; and (3) approval of additional revenue of $3.3 million related to capital tracker amounts that had not been fully approved in the 2015 capital tracker decision.
- In October 2015, a hearing to the above proceeding was completed and the decision is expected in the first quarter of 2016.

Generic Cost of Capital — Update

- In March 2015, the AUC set the allowed ROE for 2013, 2014 and 2015 at 8.3% down from 8.75% and an equity thickness of 40% down from 41%. The AUC also decided that it will not re-establish a formula-based approach to setting annual ROE as the above-mentioned rate would remain in effect for 2015 and 2016 and beyond, on an interim basis.
- The impact of changes to the ROE and deemed equity in the regulatory capital structure during the PBR term apply only to the portion of the rate base that is funded by revenue provided by mechanisms separate from the formula.

Utility Asset Disposition Proceeding — Update

- In November 2013, the AUC issued Decision 2013-417 (the UAD Decision), which decided that utilities will be responsible for the gains and losses related to extraordinary retirement of utility assets.
- FortisAlberta and other utilities filed a leave to appeal the UAD Decision with the Alberta Court of Appeal for the reason that the decision conflicts with the *Electric Utilities Act*. In August 2014, the Alberta Court of Appeal granted leave on certain issues brought forward.
- In September 2015, the Alberta Court of Appeal dismissed the appeal of the utilities on the basis that the AUC should be accorded deference for its conclusions with regards of utility asset disposition matters.
- The change in the long-standing regulatory principle, which provides a reasonable opportunity for the recovery of prudent investments in the regulated utility sector, has had a negative impact on DBRS's view of the regulatory regime in Alberta.

FortisAlberta Inc.

Balance Sheet (US GAAP)
(CA$ millions)

	Sept. 30	Dec 31			Sept. 30	Dec 31	
Assets	**2015**	**2014**	**2013**	**Liabilities & Equity**	**2015**	**2014**	**2013**
Cash & equivalents	-	-	-	S.T. borrowings	4	23	25
Accounts receivable	120	105	128	Accounts payable	182	167	168
Inventories	-	-	-	Current portion L.T.D.	-	-	200
Prepaid expenses & other	15	25	14	Deferred tax	-	-	-
Regulatory assets	11	1	3	Other current liab.	-	-	0
				Regulatory liabilities	24	42	42
Total Current Assets	**145**	**131**	**145**	**Total Current Liab.**	**210**	**233**	**434**
Net fixed assets	3,050	2,867	2,695	Long-term debt	1,684	1,534	1,259
Intangible assets	44	41	49	Deferred income taxes	195	143	102
Goodwill	227	227	227	Other L.T. liab.	21	20	19
Regulatory assets	270	205	158	Regulatory liabilities	365	352	358
Investments & others	15	14	13	Shareholders equity	1,277	1,203	1,115
Total Assets	**3,751**	**3,484**	**3,288**	**Total Liab. & SE**	**3,751**	**3,484**	**3,288**

Balance Sheet & Liquidity & Capital Ratios	9 mos. September 30		12 mos. Sept. 30	For the year ended December 31st			
	2015	2014	2015	2014	2013	2012	2011
Current ratio (x)	0.69	0.86	0.69	0.56	0.33	0.60	0.97
Total debt-to-capital	56.9%	59.4%	56.9%	56.4%	57.1%	57.3%	56.9%
Total debt-to-capital 1	57.3%	59.7%	57.3%	56.7%	57.6%	57.9%	57.3%
Cash flow-to-total debt 1	18.6%	15.6%	17.6%	17.0%	15.5%	16.2%	15.9%
Cash flow/Capex (x)	0.85	0.95	0.81	0.88	0.59	0.54	0.54
(Cash flow - dividends)/Capex (x)	0.69	0.76	0.66	0.70	0.46	0.43	0.43
Deemed common equity	40%	40%	40%	40%	40%	41%	41%
Coverage Ratios							
EBIT-to-gross interest (x) 1	2.80	2.28	2.56	2.18	2.18	2.33	2.05
EBITDA-to-gross interest (x)	4.92	4.35	4.59	4.18	4.14	4.29	4.20
Fixed-charges coverage (x) 1	2.80	2.28	2.56	2.18	2.18	2.33	2.05
Total debt/EBITDA (x)	5.80	6.73	4.50	4.55	4.72	4.50	4.66
Profitability Ratios							
EBITDA margin	68.7%	66.8%	67.5%	66.0%	66.1%	64.8%	64.3%
EBIT margin	39.1%	35.0%	37.5%	34.3%	34.6%	35.1%	31.4%
Profit margin	25.6%	20.2%	23.9%	19.8%	19.7%	21.4%	17.9%
Return on equity	11.6%	9.0%	10.3%	8.8%	8.9%	10.1%	8.4%
Allowed ROE	8.30%	8.30%	8.30%	8.30%	8.30%	8.75%	8.75%

1 Includes operating leases.

Rating History

	Current	2014	2013	2012	2011	2010
Issuer Rating	A (low)	A (low)	A (low)	A (low)	NR	NR
Senior Unsecured Notes	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)

Previous Action

- DBRS Confirms FortisAlberta Inc. at A (low), Stable Trends, December 10, 2015.

Related Research

- DBRS Comments on Quality of Regulatory Regimes in Alberta, July 23, 2015.

Previous Report

- FortisAlberta Inc., Rating Report, March 12, 2015.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on **www.dbrs.com**.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

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Rating Report

FortisBC Inc.

Eric Eng, MBA
+1 416 597 5578
eeng@dbrs.com

Chris Gifford, CEng
+1 416 597 7398
cgifford@dbrs.com

Tom Li
+1 416 597 7378
tli@dbrs.com

DBRS

Insight beyond the rating.

Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A (low)	Confirmed	Stable
Secured Debentures	A (low)	Confirmed	Stable
Unsecured Debentures	A (low)	Confirmed	Stable

Rating Update

On March 26, 2015, DBRS Limited (DBRS) confirmed the Issuer Rating, Secured Debentures and Unsecured Debentures of FortisBC Inc. (FBC or the Company) at A (low) with Stable trends. The Unsecured Debentures have the same rating as the Secured Debentures, reflecting (1) that the Secured Debentures outstanding amount is minimal (3% of total debt) and (2) that FBC does not intend to issue additional Secured Debentures.

The ratings reflect the reasonable regulatory framework, good customer mix and rate base growth over the past five years, and a solid financial profile. The ratings also reflect FBC being an integrated utility (which adds to reliability of supply and a larger rate base, given the same number of customers). FBC's owned generation assets provided approximately 45% of its 2014 energy requirement, with the remainder of the load secured largely through long-term purchase power contracts accepted by the British Columbia Utilities Commission (BCUC).

The regulatory framework is underpinned by the following factors: (1) FBC has no exposure to commodity price risk and sales volume risk as variances from the forecast are deferred, with the majority being refunded to (or collected from) customers in subsequent years. (2) The equity component in the capital structure is 40%, unchanged from previous years. Allowed return on equity (ROE) was reduced in 2013 to 9.15% from 9.90%, negatively affecting earnings. This level is, however, still comparable with other jurisdictions in Canada. (3) FBC is currently in its second year of a Performance Based Ratemaking (PBR) plan through 2019. During the term of the PBR plan, FBC's forecast risk is reduced as only one-half of variances from formulaic operation and maintenance (O&M) costs and base capital expenditures (capex) are not flow-through to customers. DBRS recognizes that O&M costs and base capex are primarily determined by a formula (see Regulation section) and that variances from the forecasted amount in the formula could affect earnings and cash flow. (4) Based on the off-ramp provision in the PBR plan, a review of the plan could be triggered if earnings in any one year vary from the approved ROE by more than +/-200 basis points (post 50/50 sharing of variances from formula-driven O&M expenses and capex) or when earnings in two consecutive years vary from the approved ROE by more than +/-150 basis points (also post 50/50 sharing). This provides FBC with some downside protection while maintaining the incentive for operational efficiency.

Continued on P.2

Financial Information

	USGAAP				CGAAP
	For the year ended December 31				
(CAD millions)	2014	2013	2012	2011	2010
EBIT-to-interest (times)	2.44	2.54	2.43	2.39	2.1
Cash flow-to-debt (*)	14.1%	13.4%	14.0%	13.4%	0.1
Debt-to-capital (**)	58.4%	59.0%	58.5%	59.6%	0.6
Cash flow-to-capex (times)	1.25	1.48	1.53	0.95	0.6
Net income before extra. items	45.1	49.6	49.0	47.5	41.8
Cash flow from operations	104.3	98.2	96.9	92.1	84.5

To be consistent with DBRS methodology, DBRS excludes in (*) "Capital Leases" that arose from FBC adopting US GAAP and in (**) Capital Leases & Goodwill that arose from FBC adopting US GAAP in 2012 (2011 was restated under US GAAP)

Issuer Description

FortisBC Inc. (FBC) is a vertically integrated utility company operating in south-central British Columbia (B.C.). FBC's regulated operations include (1) four hydroelectric generating plants (totaling 225 megawatts) on the Kootenay River in south-central B.C., (2) transmission assets, and (3) distribution assets.
FBC provides electricity services to approximately 166,400 direct and indirect customers (end of 2014). FBC is an indirect wholly owned subsidiary of Fortis Inc.

Rating Update (CONTINUED)

The direct customer base growth has also been reasonable. The customer mix is viewed by DBRS as good, as it is heavily weighted toward residential and commercial customers (70% of the 2014 load) whose consumption is sensitive to weather but not as sensitive to macroeconomic conditions as industrial customers.

FBC's financial profile remained solid and stable in 2014, with all credit metrics consistent with the current rating. The Company's major capex to extend the life and upgrade a majority of its hydroelectric units was substantially completed in 2011. The 2015 capex program ($100 million before customer contributions in aid of construction and including cost of removal) is manageable, and is expected to result in only a modest free cash flow deficit. Going forward, should substantial external financing be required, DBRS expects FBC's parent to continue to provide financial support in a timely manner and that FBC will maintain its capital structure in accordance with the regulatory capital structure and all of its key credit metrics within DBRS's "A" rating range.

Rating Considerations

Strengths

1. Reasonable regulatory environment.
FBC has most of its operations in the regulated utility business, which operates in a stable and reasonable regulatory environment. FBC is in its second year of a six-year PBR Plan. Under the PBR through 2019, there is a mechanism in place for FBC to exceed (or earn less than) the allowed return (ROE of 9.15%) through a 50/50 sharing of variances from formula-driven O&M expenses and base capex with customers. With respect to power supply costs, most power purchase contracts have been accepted by the BCUC and power supply cost variances from forecast for rate-setting purposes are recovered or refunded through future rates using regulatory deferral accounts approved by the BCUC.

2. Vertically integrated utility/supply security.
FBC is a vertically integrated regulated utility which owns generation, transmission and distribution assets. The Company's four hydroelectric generation plants, with 225 megawatts (MW) of capacity on the Kootenay River are insulated from hydrology risk as a result of the Canal Plant Agreement (see Regulation section), represent approximately 45% of the energy and 30% of the peak capacity needs of FBC in 2014. In addition, FBC has secured a mix of other long-term and short-term power purchase contracts. These contracts allow the Company to meet its electricity supply requirements.

3. Solid financial profile.
FBC's financial profile remains solid with all of its key credit metrics consistent with the current rating category. The Company's credit metrics are expected to remain stable in 2015 since the potential free cash flow deficit is expected to be modest and financed such that the regulatory capital structure (40% equity) is maintained.

4. Good customer mix/reasonable load growth.
FBC has a diverse customer base and a reasonable customer growth, with the customer mix heavily weighted toward residential and commercial, which provides a degree of stability to earnings. In 2014, approximately 41% of volume sales were sold to residential customers, 29% to commercial customers and 18% to wholesale customers (which, in turn, sell primarily to residential and commercial customers). Only 12% of sales were to low-margin, economically sensitive industrial customers. This mitigates the negative impact of an economic downturn.

Challenges

1. Managing operating and maintenance costs/base capital costs.
Managing operating and maintenance costs in order to achieve and/or exceed the productivity adjustment factor each year through 2019 is critical for FBC. The challenge is that operational efficiency has to be managed within the context of service quality measures set out by the BCUC. In addition, FBC has an ongoing capital program to maintain its current generation, transmission and distribution assets, to accommodate customer growth, and to meet reliability requirements. There can be no assurance that actual costs will be within the regulatory-approved capex, and these variances, if found imprudent by the BCUC, may not be fully recovered.

2. Lower ROE.
ROE has been reduced from 9.90% to 9.15% since 2013 and will remain at this level through 2015. This reduction has had a negative impact on earnings.

3. Reliant on parent for equity.
FBC does not have direct access to the equity market. All of its funding requirements to finance the equity portion of its capital projects would require financial support from the parent. In the event that the parent's access to the capital markets weakens significantly, it could have a negative impact of the parent's ability to inject equity into FBC in a timely manner.

Regulation/Major Contracts

Multi-Year Performance Based Ratemaking Plan for 2014 to 2019

- In July 2013, FBC filed its 2014 PBR application (2014 PBR Application), which assumed a forecast average rate base of approximately $1,192 million for 2014. The 2014 PBR Application also requested approval of a customer rate increase for 2014 of 3.3%, determined under a formula approach for operating and capital costs, and a continuation of this rate setting methodology through 2018. Effective January 1, 2014, the BCUC approved a 3.3% refundable increase on an interim basis.
- In September 2014, the BCUC issued its decision on the 2014 PBR Application as follows:

1. The term of the PBR was extended to 2019.
2. Operating and maintenance costs and base capex are subject to a formula reflecting incremental costs for inflation and half of customer growth, less a productivity adjustment factor of 1.03% each year.
3. The PBR Decision included a 50/50 sharing of variances from the formula-driven O&M and capex over the PBR period, and a number of service quality measures designed to ensure FBC maintains service levels.
4. Requirements for an annual review process were set.

- In November 2014, FBC filed a PBR Decision Compliance filing. The 2014 average rate base was updated to approximately $1,204 million. In December 2014, the BCUC approved the interim 3.3% refundable rate increase as permanent.
- In February 2015, the Company filed for approval of 2015 rates under the PBR Decision. In its filing, FBC assumed a forecast average rate base of approximately $1,267 million for 2015 and requested approval of a customer rate increase of 4.6% over 2014 rates, as determined under the PBR Plan formula approach for operating and maintenance costs, and capital costs. A decision by the BCUC is expected in Q2 2015.

Generic Cost of Capital Proceeding

- In May 2013, the BCUC issued a decision on the first stage of the Generic Cost of Capital (GCOC) proceeding. In its decision, the BCUC approved the ROE of the benchmark utility (which was determined to be FortisBC Energy Inc. (FEI)) at 8.75% and the deemed equity in the capital structure at 38.5%, both effective January 1, 2013. The deemed equity component would remain in effect through 2015.
- Effective January 2014, the BCUC introduced an Automatic Adjustment Mechanism (AAM) to set the ROE on an annual basis. The AAM will be in effect until December 31, 2015, if the actual long-term Government of Canada bond yield exceeds 3.8%. The AAM did not take effect in 2014.
- As a result of the BCUC's decision on the first stage of the GCOC, FBC's interim ROE decreased to 9.15% effective January 1, 2013, from 9.9% in 2012. The Company's deemed equity component remained unchanged at 40%.
- On March 25, 2014, the BCUC issued a decision on the second stage of the GCOC to confirm FBC's ROE of 9.15% and equity thickness of 40%.

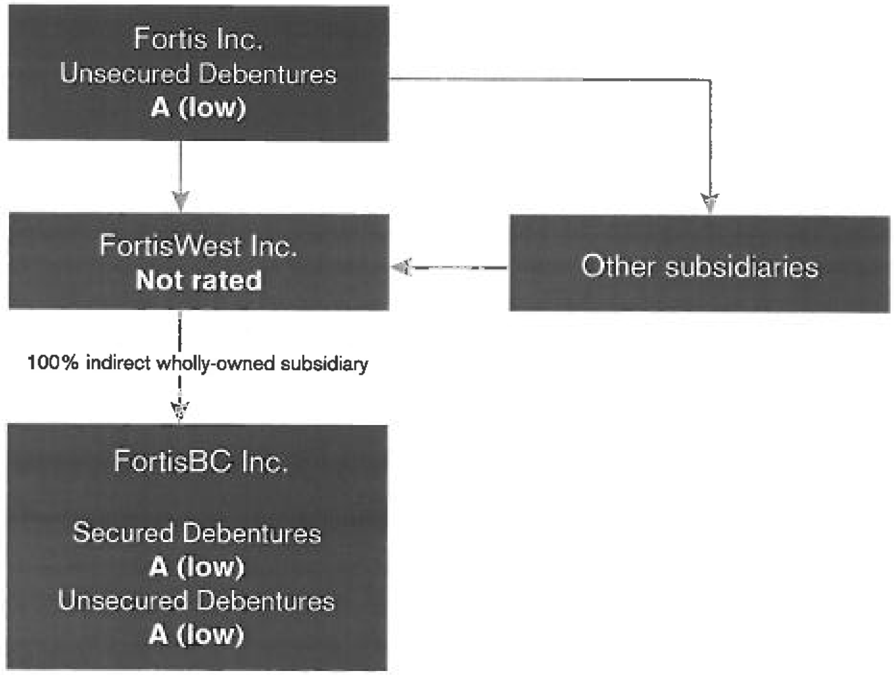
The Canal Plant Agreement

- The Canal Plant Agreement (CPA) is an agreement among British Columbia Hydro & Power Authority (BC Hydro), FBC and three other parties. The CPA governs approximately 1,600 MW of capacity of all five parties (including 225 MW of capacity owned by FBC).
- Under the CPA, BC Hydro determines the output of each plant and takes all of the power generated by the plants. BC Hydro is then contractually obligated to deliver a fixed amount of power to FBC regardless of its actual output, thus insulating FBC from hydrology risk. The CPA will remain in force until terminated by any of the parties by giving no less than five years' notice at any time on or after December 31, 2030.

Other Power Purchase Agreements

- Brilliant Power Purchase Agreement (BPPA): Supplied approximately 26% of FBC's energy requirement in 2014.
- Power purchases from BC Hydro: Provided approximately 17% of FBC's energy requirement in 2014.
- Brilliant Expansion capacity and energy purchase agreement (EPA): Supplied approximately 2% of FBC's energy requirement in 2014.
- Small power purchase contracts: Supplied less than 1% of FBC's energy requirement in 2014.
- Spot market and contracted capacity purchases: Supplied approximately 9% of FBC's energy requirement in 2014.
- Waneta Expansion Capacity Agreement (WECA): Allows FBC to purchase capacity over 40 years upon the completion of the 335 MW Waneta Expansion, expected to be in the first half of 2015. The WECA was accepted for filing as an energy supply contract by the BCUC in May 2012.

Simplified Ownership Chart as of December 31, 2014



Transition to US GAAP

Effective January 1, 2012, FBC adopted US GAAP and restated the comparative reporting period. The major impact on key credit ratios in this report reflects the following changes as at December 31, 2011:

- Total assets increased by approximately $564 million, due primarily to an increase in regulatory assets, property, plant and equipment, and goodwill.
- Total liabilities increased by approximately $344 million, due primarily to an increase in capital lease and finance obligations, and pension and other post-employment benefit liabilities.
- Shareholders' equity increased by approximately $220 million, due primarily to an increase in additional paid-in capital, partially offset by a reduction in retained earnings related to the effects of push-down accounting.
- DBRS has adjusted for the impact of capital lease and finance obligations, and goodwill for the debt-to-capital ratio under US GAAP, for comparative purposes. With respect to capital leases arising due to FBC adopting US GAAP, the BCUC has approved recovery of qualifying capital leases as operating leases for rate-setting purposes, specifically the BPPA and the Brilliant Terminal Station. DBRS excludes these capital leases when calculating the cash flow-to-debt and debt-to-capital ratios to be consistent with methodology.

Earnings and Outlook

	USGAAP				CGAAP
	For the year ended December 31				
(CAD millions)	2014	2013	2012	2011	2010
Electricity revenue	319.5	310.4	285.0	279.4	248.8
Other revenue (expenses)	5.2	(1.7)	8.4	3.3	8.1
Power puchase costs	(86.7)	(83.3)	(76.0)	(71.6)	(73.0)
Net sales	**238.0**	**225.4**	**217.4**	**211.1**	**183.9**
Operating, maintenance & other	(82.0)	(76.8)	(73.3)	(70.8)	(63.9)
EBITDA	**156.0**	**148.6**	**144.1**	**140.3**	**120.1**
Depreciation & amortization	(59.3)	(49.7)	(48.5)	(45.3)	(41.6)
EBIT	**96.7**	**98.9**	**95.6**	**95.0**	**78.4**
Net interest expense	(40.2)	(38.5)	(38.5)	(39.0)	(32.5)
Other income (expense)	0.4	1.2	0.7	0.9	0.0
Pre-tax income	**56.9**	**61.6**	**57.8**	**56.9**	**45.9**
Income tax	(11.8)	(12.0)	(8.8)	(9.4)	(4.2)
Net income before extra. items	**45.1**	**49.6**	**49.0**	**47.5**	**41.8**
Reported net income	**45.1**	**49.6**	**49.0**	**47.5**	**41.8**
Regulated rate base (CAD millions)	1,204.0	1,204.0	1,112.0	1,093.2	975.0
Approved deemed equity	40%	40%	40%	40%	40%
Allowed ROE	9.15%	9.15%	9.90%	9.90%	9.90%

2014 Summary

- A modest decrease in net earnings in 2014 compared to 2013 primarily reflected the following factors: (1) earnings in 2013 benefited from increased allowance for funds used during construction and a decrease in interest and depreciation expense as compared to the forecasted amounts used to set 2013 rates; and (2) higher 2013 income tax expense driven primarily by lower tax timing differences.
- Earnings in 2014 were based on an allowed ROE of 9.15% and a deemed equity component of the capital structure of 40% (unchanged from 2013). The rate base was also substantially unchanged from 2013.
- Variances arising from the differences between actual power purchase costs and electricity sales volume compared to forecasts used to determine electricity revenues had no impact on net earnings 2014, 2013 and 2012, as these variances were deferred and will be flowed back to customers in future rates, eliminating the Company's exposure to the volatility of purchase power costs and sales volume.

2015 Outlook

- Earnings in 2015 are expected to remain stable as they continue to be based on (1) an allowed ROE of 9.15% and (2) a deemed equity component of the capital structure of 40%, both of which are unchanged from 2014. The increase in regulated rate base should modestly increase earnings in 2015.
- Based on the incentive mechanisms under the current PBR plan and its formulaic approach, the ability of the Company to manage its operations & maintenance costs and base capex costs will be key for the Company to achieve or exceed its allowed ROE.

Financial Profile

	USGAAP				CGAAP
	For the year ended December 31				
(CAD millions)	2014	2013	2012	2011	2010
Net income before extra. items	45.1	49.6	49.0	47.5	41.8
Depreciation & amortization	59.7	50.1	48.9	45.7	42.0
Deferred income taxes/Other	(0.5)	(1.5)	(1.0)	(1.1)	0.7
Cash flow from operations	**104.3**	**98.2**	**96.9**	**92.1**	**84.5**
Dividends	(28.0)	(46.0)	(24.0)	(16.0)	(15.0)
Capex	(83.7)	(66.4)	(63.4)	(96.7)	(142.8)
Free cash flow before WC	**(7.4)**	**(14.2)**	**9.5**	**(20.6)**	**(73.3)**
Working capital (WC)	(13.1)	(8.0)	(9.4)	7.7	1.1
Regulatory assets & liabilities	14.6	7.0	(0.5)	(3.9)	0.0
Net free cash flow	**(5.9)**	**(15.2)**	**(0.4)**	**(16.8)**	**(72.3)**
Acquisitions	0.0	(55.1)	0.0	0.0	0.0
Other investment activities	0.0	0.0	0.0	0.0	0.0
Net changes in equity	0.0	17.3	0.0	0.0	10.0
Net changes in debt	4.6	51.4	1.5	15.5	62.1
Other	2.0	0.3	0.7	1.3	0.1
Change in cash	**0.7**	**(1.3)**	**1.8**	**0.0**	**(0.0)**
EBITDA	156.0	148.6	144.1	140.3	120.1
Total debt *	716.9	712.3	660.9	659.8	663.7
Cash flow-to-debt *	14.1%	13.4%	14.0%	13.4%	12.7%
Debt-to-capital **	58.4%	59.0%	58.5%	59.6%	60.5%
EBIT-to-interest (times)	2.44	2.54	2.43	2.39	2.11

* To be consistent with DBRS methodology, DBRS excludes Capital Leases that arose due to FBC adopting US GAAP in 2012 (2011 was restated under US GAAP)
** To be consistent with DBRS methodology, DBRS excludes Capital Leases & Goodwill that arose due to FBC adopting US GAAP in 2012 (2011 was restated under US GAAP)

2014 Summary

- FBC's financial profile remained solid in 2014, with all key credit metrics maintained within the current rating range.
- Operating cash flow growth in 2014 reflected higher depreciation approved by the BCUC.
- The equity injection in 2013 was to finance the non-regulated portion of the City of Kelowna acquisition.
- A modest free cash flow deficit incurred in 2014 and was largely financed with debt. This debt financing did not have any material impact on FBC's credit metrics.

2015 Outlook

- A modest free cash flow deficit is expected in 2015 as a result of the ongoing capex program. FBC projects its capex for 2015 to be approximately $100 million (before customer contributions and including cost of removal).
- This cash flow deficit is expected to be financed in a manner so that the regulatory capital structure (40% equity and 60% debt) will be maintained.
- As a result, the Company's key credit ratios are expected to remain stable and within the current rating range.

Liquidity and Debt Profile

Credit facilities (As at December 31, 2014)

(CAD millions)	Committed	Drawn	Available	Maturity
Facility A, revolving	100.0	20.0	80.0	May 2017
Facility B, 364-day revolving	50.0	5.0	45.0	April 2015
Operating facilities	**150.0**	**25.0**	**125.0**	
Demand overdraft facility	10.0	6.9	3.1	
Total	**160.0**	**31.9**	**128.1**	

- FBC's liquidity remains sufficient to fund its ongoing operational and capital requirements.
- Two years prior to the expiry of Facility A, the Company may request an extension for a further 364 days, and if the request is not granted, all outstanding debt under Facility A will become due on the maturity date.
- The Company may also request an extension of Facility B for another 364 days, and if the request is not granted, Facility B will be converted into a non-revolving term loan and will mature six months from that date.
- FBC could request an additional amount of $50 million under Facility A or B, or a combination of the two facilities.
- As at December 31, 2014, FBC had no material off-balance sheet arrangements.

Debt Instruments Maturity Schedule (As at December 31, 2014)

(CAD millions)	2015	2016	2017	2018	2019	Thereafter	Total
Unsecured Debentures	-	25.0	-	-	-	635.0	660.0
Secured Debentures	-	-	-	-	-	25.0	25.0
Overdraft demand facility	6.9	-	-	-	-	-	6.9
Operating credit facilities	5.0	-	20.0	-	-	-	25.0
Sub-total	**11.9**	**25.0**	**20.0**	-	-	**660.0**	**716.9**
Less: Current portion of debt							(11.9)
Long-term debt							**705.0**

- The Unsecured Debentures maturity schedule presents minimal refinancing risk over the next five years with only $25 million due in 2016.
- In July 2013, the Company filed a short form base shelf prospectus to establish a Medium Term Note Debenture (MTN Debentures) Program. The Company can issue up to $300 million under the MTN Debentures Program during the 25-month life of the shelf prospectus. As of December 31, 2014, the Company has issued $200 million of senior unsecured MTN Debentures under the Program.

Description of Operations

FBC operates in south-central British Columbia and owns the following assets:

1. Transmission

- The Company owns a 1,340 kilometre transmission system which interconnects with the BC Hydro system.
- Transmission assets represented approximately 32% of the Company's 2014 rate base assets.

2. Distribution

- FBC serves approximately 130,572 direct customers (approximately 166,400, including indirect), with most being residential or commercial customers.
- Distribution assets represented approximately 44% of the Company's 2014 rate base assets.
- In 2014, approximately 70% of FBC's electricity sales were to relatively stable residential and commercial customers, 12% to industrial customers and 18% to wholesale customers, which resell the power to their own residential and commercial customers.

3. Generation

- The Company owns four hydroelectric plants, with 225 MW of capacity, which provided approximately 45% of its energy and 30% of its peak capacity needs in 2014.
- Generation assets represented approximately 15% of FBC's 2014 rate base assets.
- Electricity production from these plants is insulated from hydrology risk in accordance with the CPA (see Regulation section).

4. Other regulated assets

- Other regulated assets consist of those supporting the maintenance and operation of the system, such as office and service buildings, transport and work equipment, and other office and information technology assets.
- These assets represented approximately 9% of FBC's 2014 rate base assets.

5. Non-regulated assets

- FBC also has a limited number of non-regulated operations, principally made up of the Walden Power Partnership, the owner of a hydroelectric generating plant.
- The plant is a 16 MW run-of-river, hydroelectric station that sells all of its output to BC Hydro. In January 2015, FBC and BC Hydro agreed to suspend the right to terminate the agreement prior to 2024.

FortisBC Inc.

Balance Sheet

	USGAAP As at December 31		
	2014	2013	2012
Assets (CAD millions)			
Cash & equivalents	1.2	0.5	1.8
Accounts receivable	50.1	52.3	39.8
Deferred tax	3.1	5.2	0.6
Regulatory assets	7.2	9.0	6.3
Other current assets	1.7	1.9	1.9
Total Current Assets	**63.3**	**68.9**	**50.4**
Net fixed assets	1,419.2	1,374.4	1,323.4
Intangibles	52.7	45.5	44.8
Regulatory assets	280.8	274.4	285.1
Goodwill	234.8	234.8	220.7
Other assets	9.2	6.1	6.7
Total Assets	**2,060.0**	**2,004.1**	**1,931.1**

	USGAAP As at December 31		
	2014	2013	2012
Liabilities & Equity			
Accounts payable	58.5	43.2	41.6
Current portion of L.T. debt	12.4	171.8	1.4
Deferred tax	2.5	3.2	2.1
Regulatory liabilities	9.2	15.6	2.0
Other current liabilities	2.6	4.3	0.3
Total Current Liab.	**85.2**	**238.1**	**47.4**
Long-term debt	705.0	541.0	660.0
Capital lease obligations	308.6	305.7	312.4
Deferred income taxes	129.8	125.8	110.3
Pension/OPEB	63.5	56.4	30.5
Regulatory liabilities	17.9	4.0	7.0
Other L.T. liabilities	2.2	2.4	3.7
Shareholder's equity	747.8	730.7	709.8
Total Liab. & SE	**2,060.0**	**2,004.1**	**1,931.1**

	USGAAP For the year ended December 31				CGAAP
	2014	2013	2012	2011	2010
Balance Sheet & Liquidity & Capital Ratios					
Current ratio (times)	0.74	0.29	1.06	0.61	0.82
Cash flow/Capex (times)	1.25	1.48	1.53	0.95	0.59
(Cash flow - dividends)/Capex (times)	0.91	0.79	1.15	0.79	0.49
Dividend payout ratio	62.1%	92.7%	49.0%	33.7%	35.9%
Key Credit Metrics					
Cash flow-to-debt *	14.1%	13.4%	14.0%	13.4%	12.7%
Debt-to-capital **	58.4%	59.0%	58.5%	59.6%	60.5%
EBIT-to-interest (times)	2.44	2.54	2.43	2.39	2.11
EBITDA-to-interest (times)	3.93	3.81	3.66	3.53	3.22
Fixed-charges coverage (times)	2.44	2.54	2.43	2.39	2.11
Debt-to-EBITDA (times)	4.60	4.79	4.59	4.70	5.53
Profitability Ratios					
EBITDA margin	65.5%	65.9%	66.3%	66.5%	65.3%
EBIT margin	40.6%	43.9%	44.0%	45.0%	42.6%
Profit margin	18.9%	22.0%	22.5%	22.5%	22.7%
Return on common equity	6.1%	6.9%	7.0%	10.6% ‡	10.1%
Return on capital	4.2%	4.6%	4.7%	6.8% ‡	6.2%

* To be consistent with DBRS methodology, DBRS excludes Capital Leases that arose due to FBC adopting US GAAP in 2012 (2011 was restated under US GAAP)
** To be consistent with DBRS methodology, DBRS excludes Capital Leases & Goodwill that arose due to FBC adopting US GAAP in 2012 (2011 was restated under US GAAP)
‡ These two ratios in 2011 were calculated based on CGAAP.

Rating History

	Current	2014	2013	2012	2011	2010	2009
Issuer Rating	A (low)	A (low)	A (low)	NR	NR	NR	NR
Secured Debentures	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)	BBB (high)
Unsecured Debentures	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)	BBB (high)

Previous Report

- FortisBC Inc., Rating Report, March 28, 2014.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on **www.dbrs.com**.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

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Rating Report

Gaz Métro inc.

DBRS

Insight beyond the rating.

James Jung, CFA, FRM, CPA, CMA
+1 416 597 7577
jjung@dbrs.com

Tom Li
+1 416 597 7378
tli@dbrs.com

Jordan Kremblewski
+1 416 597 7530
jkremblewski@dbrs.com

Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable
First Mortgage Bonds*	A	Confirmed	Stable
Senior Secured Notes*	A	Confirmed	Stable

* Guaranteed by Gaz Métro Limited Partnership.

Rating Update

DBRS Limited (DBRS) has confirmed the ratings of Gaz Métro inc. (GMi or the Company) as listed above, all with Stable trends. The ratings of GMi are based on the credit quality of Gaz Métro Limited Partnership (GMLP or the Partnership), which guarantees GMi's First Mortgage Bonds (FMB), Senior Secured Notes and a secured credit facility that supports the Commercial Paper (CP). GMi is the general partner of GMLP and serves as its financing entity.

The credit quality of the Partnership has remained relatively stable over the past year. GMLP's diverse portfolio of low-risk regulated businesses, which accounted for more than 95% of consolidated earnings for the fiscal year ended September 30, 2015 (F2015), have continued to provide predictable earnings and cash flow. Recent regulatory decisions have also all been reasonable. In May 2015, the Régie de l'énergie (the Régie), approved the authorized return on deemed equity (ROE) for 2016 and 2017 at 8.90% for the GMLP's flagship entity, Gaz Métro-QDA, unchanged from 2015. DBRS views the recently authorized ROE for 2016 and 2017 as being fair given the continued low interest rate environment. As for Green Mountain Power Corporation (GMP), GMLP's electricity distribution utility subsidiary based in Vermont, the authorized ROE for 2015 was reasonable at 9.44%. GMP has an opportunity to earn a higher actual ROE than that of the authorized ROE if GMP achieves its annual target merger savings (estimated at USD 21 million in 2016; of which 50% is retained by GMP). These two utilities combined accounted for approximately 85% of the Partnership's consolidated earnings in F2015. GMLP's smaller gas distribution utility, Vermont Gas Systems, Inc. (VGS; approximately 5% of total earnings), is exposed to construction cost overrun risk. The Addison Natural Gas Project's capital budget has increased to USD 154 million from its 2013 initial estimate of USD 86 million. As a result, the Partnership took a pre-tax impairment charge of USD 10.3 million in F2015 following the agreement reached with the Vermont Department of Public Service. Negative earnings and cash flow impacts from the project cost overrun have been manageable within the current rating category.

The Partnership's financial risk profile remained relatively stable in F2015 from F2014. Looking into F2016, DBRS does not expect any significant change in the Partnership's financial risk profile as its estimated capital expenditure (capex) for F2016 (approximately $485 million excluding greenhouse gas emission allowance purchases) is expected to be financed in a prudent manner. In 2015, GMLP completed two equity offerings for aggregated gross proceeds of $255 million to maintain leverage in line with the regulatory target. Incremental earnings (supported by the sustained growth of regulated activities and higher earnings contribution from GMLP's wind farm projects) are expected to be used to fund higher distributions.

Financial Information

Gaz Métro Limited Partnership (consolidated)

	For the year ended September 30th				
(CA$ millions)	2015	2014	2013	2012	2011
EBIT gross interest coverage (times) 1	1.82	1.85	1.83	2.11	2.42
Total debt in capital structure 1,2	67.2%	67.9%	65.3%	63.7%	62.1%
Cash flow/Total debt 1	15.7%	14.4%	12.6%	13.0%	18.2%

1 Adjusted for operating leases. 2 Adjusted for accumulated other comprehensive income.

Issuer Description

GMi is a holding company with majority ownership of GMLP. GMLP owns and operates natural gas distribution in Québec and natural gas and electricity distribution in Vermont, as well as financial interests in transmission, storage, gas and other underground systems enterprises. GMLP is 71% owned by GMi and 29% owned by Valener Inc.

Rating Considerations

Strengths

1. Supportive regulation in Québec
The regulatory framework in Québec is viewed as supportive, reflecting the following factors: (a) full recovery on gas supply costs through an automatic monthly adjustment mechanism, (b) rate stabilization accounts to mitigate revenue fluctuations due to the weather and (c) a reasonable ROE.

2. Reasonable financial profile
GMLP's consolidated financial profile has remained reasonable. The Partnership has maintained an acceptable cash flow-to-debt ratio for the current rating category. Although the consolidated debt-to-capital (67.2%) and consolidated EBIT gross interest coverage (1.82 times) were slightly weaker than the "A" rating range in F2015, respective non-consolidated ratios were reasonable (non-consolidated leverage at 53.8%, interest coverage at 1.72 times and cash flow-to-debt at 18.4%). GMLP's non-consolidated financial statements are presented from the perspective of its directly owned, flagship entity, Gaz Métro-QDA by removing the impact of consolidation of investments in subsidiaries and financial interests, including GMP, VGS, Trans Québec & Maritimes Pipeline Inc. (TQM; rated A (low) by DBRS) and wind farm projects.

3. Cash flow diversification
The Partnership benefits from a large base of regulated utility assets, including: (a) gas distribution in Québec; (b) U.S. natural gas and electricity distribution in Vermont through GMP and VGS; (c) U.S. electricity transmission in Vermont through majority ownership in Vermont Electric Power Company, Inc. and Vermont Transco LLC; (d) financial interest in three natural gas transportation enterprises, namely TQM, Portland Natural Gas Transmission System (PNGTS) and Champion Pipe Line Corporation Limited (Champion); and (e) financial interests in wind power projects.

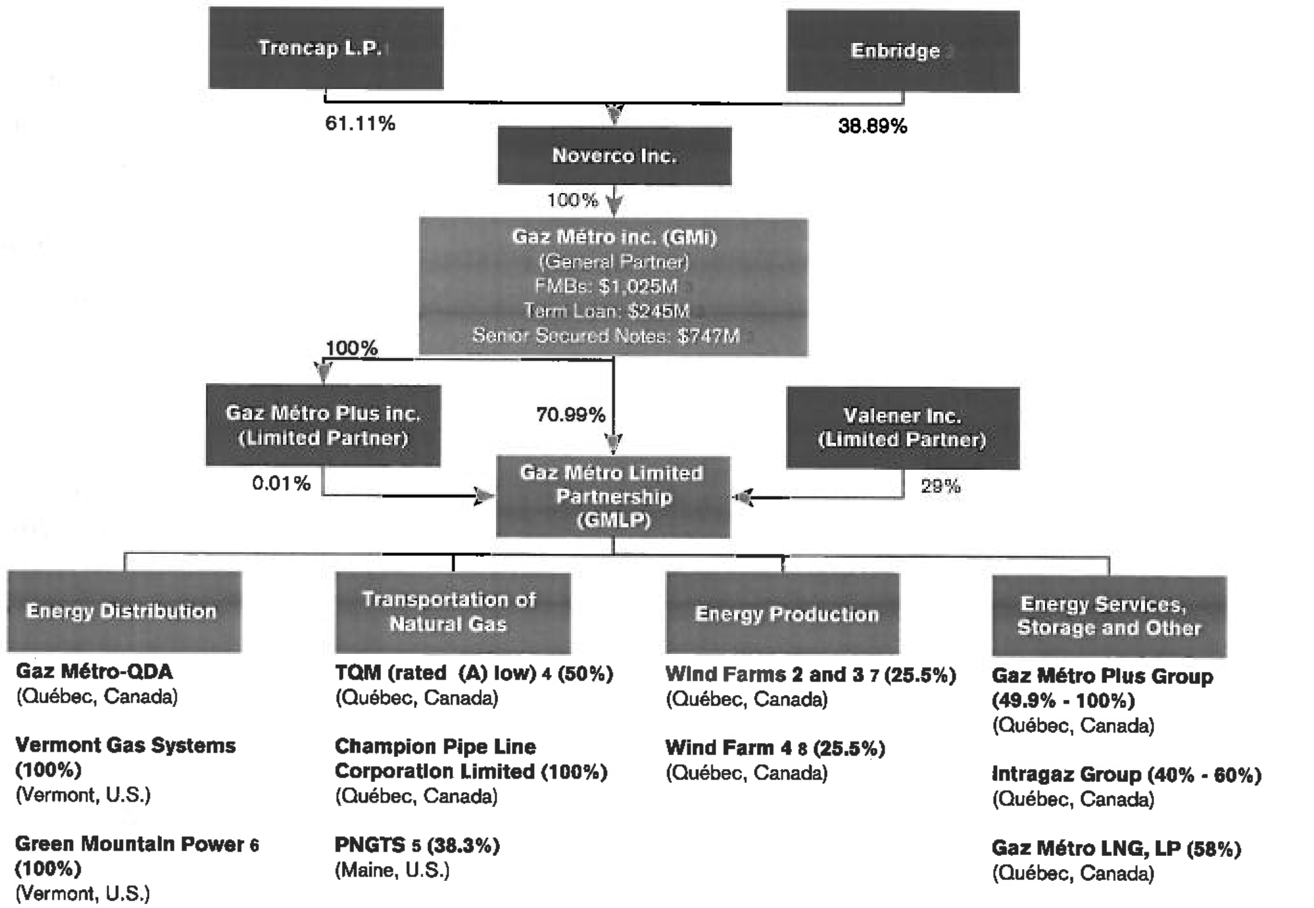
Challenges

1. Higher risks associated with volume and energy cost in Vermont electricity distribution
There is a higher level of volume risk associated with regulated operations in Vermont than in Québec, as there is no rate stabilization mechanism for GMLP's utility subsidiaries in Vermont to mitigate against volume delivery fluctuations due to the weather. In addition, GMP (the larger of the two Vermont utility subsidiaries) faces potential exposure to rising energy costs (refer to the Regulation Update section).

2. Project cost overrun risk associated with Addison Gas Project
GMLP's smaller gas distribution utility in Vermont, VGS, is exposed to construction cost overrun risk. The capital budget of VGS's major capital project, the Addison Natural Gas Project, has increased approximately 79% to USD 154 million from its 2013 initial estimate of USD 86 million. As a result, the Partnership took a pre-tax impairment charge of USD 10.3 million in F2015 following the agreement reached with the Vermont Department of Public Service. However, negative earnings and cash flow impacts from the project cost overrun have been manageable within the current rating category.

3. Industrial customers are sensitive to economic conditions
In Québec, approximately 60% of natural gas distribution is consumed by industrial customers, whose consumption is highly sensitive to economic conditions. A significant reduction in demand from these customers could affect GMLP's distribution revenues. However, this risk is mitigated by firm service contracts, with a large number of these customers providing guaranteed payment of a significant portion of distribution services, regardless of their levels of consumption. Firm service contracts accounted for more than 80% of all industrial volume consumption.

Simplified Organizational Chart



1 The general partner of Trencap was Capital d'Amérique CDPQ inc., a subsidiary of Caisse de dépôt et placement du Québec which, as a limited partner of Trencap, held 59.64% of its units. The other limited partners were Fonds de solidarité des travailleurs du Québec (F.T.Q.) (19.11%), British Columbia Investment Management Corporation (13.01%), the Régime des rentes du Mouvement Desjardins (6.87%) and the Régime de retraite de l'Université du Québec (1.37%).
2 Enbridge Inc. held its shares through its subsidiary, IPL System Inc.
3 FMBs, Senior Secured Notes and the term loan at GMi are guaranteed by GMLP. Balances are as at September 30, 2015.
4 TQM refers to Trans Québec & Maritimes Pipeline Inc.
5 PNGTS refers to Portland Natural Gas Transmission System.
6 Includes Central Vermont Public Service Corporation; acquired in 2012.
7 Wind Farms 2 and 3 refers to the 272 megawatt (MW) Seigneurie de Beaupré Wind Farms 2 and 3 General Partnership
8 Wind Farm 4 refers to the 69 MW Seigneurie de Beaupré Wind Farm 4 General Partnership

Notes

- GMi is the financing vehicle for GMLP, with funds raised loaned to GMLP on similar terms and conditions as those imposed on GMi.
- Given the mirror-like structure of the financing, the only substantive difference between the two entities is the subordinated debt at GMi (intercompany debt from Noverco, Inc.), which was $892.8 million outstanding on September 30, 2015 (not rated by DBRS), and not shown in the chart above.
- As at September 30, 2015, GMLP's interests in non-regulated energy-related activities and in non-energy-related activities were relatively limited.
  - The trust deeds stipulate that all of the Partnership's interest in non-regulated energy-related activities and non-energy-related activities must not be more than 10% of its total non-consolidated assets. As at September 30, 2015, the Partnership's assets used for such activities accounted for 3.17% of its total non-consolidated assets.
  - As for non-energy-related activities, GMLP's interest in such activities may not exceed 5% of its total non-consolidated assets. As at September 30, 2015, the Partnership had no interest in such activities.

Consolidated Earnings and Outlook

Gaz Métro Limited Partnership (consolidated)

(CA$ millions)	2015	2014	2013	2012	2011
	For the year ended September 30th				
EBITDA	593	543	461	402	417
EBIT	322	295	258	239	242
Gross interest expense	177	160	142	114	100
Total share in earnings	92	77	62	29	23
Net income before non-recurring items	192	175	166	152	147
Reported net income	184	175	180	144	164
Return on avg. common equity	11.7%	11.6%	11.3%	12.1%	14.3%

F2015 Summary

- Net income before non-recurring items increased approximately 10% in F2015 from F2014, mainly due to the following factors:
  - A favourable exchange rate impact on earnings generated by Vermont energy distribution activities.
  - An increase in rate base for Gaz Métro-QDA.
  - Higher earnings from shares in earnings of entities subject to significant influence, largely due to a favourable exchange rate and the greater ownership in Velco and Transco (increased to 71.5% from 70.0%).
  - Higher energy production activities given favourable winds and new wind projects came into service (Wind Farms 2 and 3 ran for a full 12 months in F2015 versus ten months in F2014, and Wind Farm 4 came in service in December 2014).
- Reported net income was lower than earnings before non-recurring items, because of an impairment charge related to the Addison project following the agreement reached with the Vermont Department of Public Service.

Reported Net Income Breakdown

For the year ended September 30th	FY 2015		FY 2014	
Gaz Metro - QDA	58.6%	116	61.2%	111
VGS and GMP	28.9%	57	32.1%	58
Natural Gas Transportation	8.5%	17	8.9%	16
Energy Production	2.7%	5	-0.5%	(1)
Energy Services, Storage and Other	1.2%	2	-1.6%	(3)
Total	**100.0%**	**197**	**100.0%**	**182**
Corporate Affairs		(9)		(8)
Total		**188**		**174**

- Over 95% of the Partnership's consolidated earnings were generated by low-risk regulated utilities and pipelines supported by long-term contracts in F2015.

F2016 Outlook

- Earnings are expected to grow modestly in F2016 as a result of the sustained growth of the Partnership's regulated activities and higher earnings contribution from the wind farm projects due to their full-year effects.

Consolidated Financial Profile

Gaz Métro Limited Partnership (consolidated)

Cash Flow Statement	For the year ended September 30th				
(CA$ millions)	2015	2014	2013	2012	2011
Net income before non-recurring items	192	175	166	152	147
Depreciation & amortization	346	252	205	166	177
Distributions received	71	65	36	30	14
Non-cash share in earnings	(92)	(77)	(62)	(29)	(23)
Deferred income taxes/Other	51	45	12	8	7
Cash flow from operations	**569**	**460**	**356**	**327**	**323**
Distributions to partners	(187)	(169)	(165)	(141)	(106)
Capex	(779)	(471)	(475)	(471)	(215)
Gross free cash flow	**(396)**	**(180)**	**(284)**	**(286)**	**2**
Change in working capital	31	12	45	37	(5)
Change in regulatory assets & deferred charges	(61)	17	(84)	(81)	(27)
Net free cash flow	**(426)**	**(152)**	**(323)**	**(330)**	**(29)**
Acquisitions/Long-term investments	(36)	(26)	6	(485)	21
Net change in equity	259	4	56	382	106
Net change in debt	121	241	292	490	(96)
Other	64	(25)	(13)	(53)	(13)
Change in cash	(17)	42	19	5	(10)
Total debt	3,600	3,173	2,805	2,484	1,767
Total debt in capital structure 1,2	67.2%	67.9%	65.3%	63.7%	62.1%
EBIT gross interest coverage (times) 1	1.82	1.85	1.83	2.11	2.42
Cash flow/Total debt 1	15.7%	14.4%	12.5%	13.0%	18.2%
Distribution payout ratio	97.0%	96.8%	99.7%	93.3%	72.0%

1 Adjusted for operating leases. 2 Adjusted for accumulated other comprehensive income.

F2015 Summary

- Overall, the Partnership's consolidated key credit metrics remained relatively stable in F2015 from F2014.
- Operating cash flow increased, predominately due to additional Gaz Métro-QDA revenues attributable to the Cap and Trade System (C&T) regulation-related greenhouse gas emissions allowances. As emission costs associated with the C&T regulation is fully passed onto ratepayers, deprecation increased materially in F2015.
- Capex increased sharply in F2016, predominately due to the purchase of greenhouse gas emission allowances related to the C&T regulation ($365 million in F2015 versus $0 in F2014), enough to cover almost 60% of expected customers emission for the 2015–2020 period.
- The Partnership distributed virtually 100% of its net income to its limited partners. Under the Partnership Agreement, the Partnership will not, except under extraordinary circumstances, distribute any less than 85% of its net income before non-recurring items to its partners.
- The Partnership financed cash flow deficits through a reasonable mix of debt and equity. In 2015, the Partnership completed two equity offerings for aggregated gross proceeds of $255 million. As a result, leverage remained relatively unchanged in F2015 from F2014.

F2016 Outlook

- The Partnership's financial profile is expected to remain relatively stable in F2016.
- Incremental earnings are expected to be used to fund higher distributions. The Partnership announced that it would raise its quarterly distribution by 3.6%, beginning with its next distribution to be made on January 5, 2016.
- The financing of an estimated $470 million in capex for F2016 (excluding greenhouse gas emission allowance purchases) is not expected to have a material impact on the current key metrics. Key financial metrics are expected to remain relatively stable in F2016.

Liquidity

Credit facilities (non-consolidated)

As at Sept. 30, 2015	Maturity	Committed	Oustanding*	Available
Secured Term Loan	Mar-2020	800	282	518
Total		**800**	**282**	**518**

* Includes letters of credit ($37 million as at Sept. 30, 2015)

- GMi's reliance on short-term borrowing is expected to remain manageable.
- GMi has an investment policy in place such that GMi should not have CP maturities in excess of an aggregate amount of $35 million for two consecutive business days, to ensure that the $50 million swingline facility, which is available under GMi's credit facility, maintains adequate liquidity to backstop the CP program.
- The Partnership and GMi have a joint secured credit line (term loan) of $800 million to support the CP program, with GMi as the borrower. The debt issued under this term loan is guaranteed by the Partnership, and will expire in March 2020.
- GMi is expected to continue to reserve capacity under its bank credit facilities for amounts outstanding under the CP program.

Long-Term Debt

The following is a table of the debt maturities of GMLP on a consolidated basis:

Consolidated Debt maturities as of Sept 30, 2015

(CA$ millions)	2015	2016	2017	2018	2019	Thereafter	Total
Gaz Métro	-	-	125	-	100	1,792	2,017
NNEEC	-	-	67	-	-	67	133
VGS	-	-	-	-	-	73	73
GMP 1	-	-	-	29	115	742	886
Intragaz	-	-	-	-	-	42	42
TCM	-	-	50	52	-	-	102
Wind Farms 2 and 3	-	-	-	-	-	250	250
Wind Farm 4	6	-	-	-	-	70	76
Other 2	-	-	-	0	-	17	17
Sub Total	**6**	**-**	**242**	**82**	**215**	**3,053**	**3,598**
Financing costs							(33)
Total							**3,564**

1 Includes Series 2010A First mortgage bonds in an amount of US$28.6 million maturing in tranches of variable amounts on April 1 of each year (2015-2035).
2 Includes Secured term loans in an amount of $16.6 million maturing from 2016 to 2023.

- The debt maturity schedule is reasonably spread out with minimal refinancing risk over the next five years.

Covenants and Restrictions

- GMLP has restrictive covenants, in which if its long-term debt-to-total capitalization ratio exceeds 65%, and its long-term debt interest coverage ratio is less than 1.5 times (both on a non-consolidated basis), it may not issue any additional long-term debt.
- If the Partnership's long-term debt-to-capitalization ratio exceeds 75% (on a non-consolidated basis), it will not make a distribution to its partners.
- As of September 30, 2015, GMLP's non-consolidated long-term debt-to-total capitalization ratio and the non-consolidated long-term debt interest ratio were 52.8% and 2.94 times, respectively.
- The trust deeds stipulate that all of the Partnership's interest in non-regulated energy-related activities and non-energy-related activities must not be more than 10% of its total non-consolidated assets. As at September 30, 2015, the Partnership's assets used for such activities accounted for 3.17% of its total non-consolidated assets.

As for non-energy-related activities, GMLP's interest in such activities may not exceed 5% of its total non-consolidated assets. As at September 30, 2015, the Partnership had no interest in such activities.

Regulation Update

1. Gaz Métro-QDA — Regulated by the Régie

Gaz Métro-QDA expects to continue using the cost-of-service (COS) method until a new incentive mechanism is implemented, which is expected for F2018. The regulatory framework in Québec is viewed as supportive, with major features as follows:

- All natural gas supply costs are fully passed on to customers through an automatic monthly adjustment mechanism.
- All the transportation costs charged by TransCanada PipeLines Limited (TCPL; rated A (low) with a Stable trend by DBRS) are included in the COS of Gaz Métro-QDA and are reflected in its transportation rates. These costs include TCPL's rate adjustments based on the recent approval by the NEB of agreement-in-principle among TCPL, Gaz Métro-QDA and Ontario natural gas distributors (effective January 1, 2015).
- Under the COS methodology, Gaz Métro-QDA is allowed to recover the cost of providing its service and to earn a reasonable rate of return on its rate base.

Main Features of the F2016–F2017 Rate Cases versus F2015:

- Gaz Métro-QDA's capital structure remains the same at 54.0% in the form of debt, 7.5% in the form of deemed preferred shares and 38.5% in the form of deemed common equity.
- The return on deemed common equity also remains the same at 8.90%.
- Gaz Métro-QDA has been subject to the C&T regulation effective January 1, 2015. The compliance cost is fully passed onto ratepayers.

2. Vermont Distribution Utilities – Regulated by Vermont Public Service Board (VPSB)

GMP and VGS are regulated by the VPSB. Rates for their activities are established based on alternative regulation plans, which is more similar to a traditional COS method than a typical longer-term performance-based regulation plan. The base rates for the Partnership's Vermont utilities are approved annually by the VPSB, whereas natural gas and electricity prices are adjusted quarterly or annually using the rate adjustment mechanism in place.

The following table summarizes the key regulatory parameters for the two Vermont utility subsidiaries in F2015 and F2014.

	F2015		F2014	
	Deemed equity	Authorized ROE	Deemed equity	Authorized ROE
GMP	50.00%	9.60%	49.56%	9.58%
VGS	55.00%	10.20%	55.00%	10.26%

GMP

- GMP is a combined entity of Green Mountain (pre-merger) and Central Vermont Public Service Corporation. The merger became effective October 1, 2012.
- As part of the merger agreement, GMP agreed to the following merger saving sharing plan during the first ten years following the close of the merger: (1) flow through to ratepayers via a rate credit USD 2.5 million in 2013; (2) USD 5 million in 2014; (3) USD 8 million in 2015; (4) 50% of total savings from 2016 to 2020 (estimated at USD 10.5 million in 2016, USD 12 million in 2017, USD 13 million in 2018, USD 14 million in 2019 and USD 14.5 million in 2020); and (5) all savings in 2021 and 2022. GMP is required to file a savings guarantee plan with the VPSB by December 31, 2022, to compensate ratepayers if the total merger saving is less than USD 144 million during the ten-year period.
- Normally the rate adjustment mechanism for electricity generation costs is conducted quarterly. However, for F2015 this adjustment mechanism is applied annually.
- In August 2014, the VPSB approved GMP's three-year alternative regulation plan (ARP) for the period from October 1, 2014, to September 30, 2017. The main features are as follows:
  - Annual base rate adjustment.
  - Power supply adjustment mechanism as follows: (1) 90% of energy costs that are USD 615,000 (per quarter) higher or lower than energy costs are included in rates and (2) a full amount of transmission and capacity costs higher or lower than the amount already included in rates.
  - A formula to determine the authorized ROE on common equity.
  - Sharing of revenue shortfalls when returns are less than those allowed on shareholders' equity.
  - Opportunity to recover costs of exogenous factors in excess of USD 1.2 million per year.

VGS

- VGS is subject to an ARP, which includes: (1) a quarterly adjustment of gas costs sold to customers and (2) an annual rate application for other activities.
- The annual rate application includes a mechanism for productivity gains, along with an earnings-sharing mechanism when the actual ROE is outside of a 50 basis point dead band from the authorized ROE.

Regulation Update (CONTINUED)

3. Vermont Electricity Transmission – Regulated by the Federal Energy Regulatory Commission (FERC) in the U.S.

- Vermont Transco LLC (Transco), which is 71.5% indirectly owned by GMLP, owns transmission assets in Vermont.
- Transco operates under a COS framework regulated by the FERC, which allows Transco to recover all prudently incurred operating costs.
- Transco is not exposed to any volume or commodity risk.
- In October 2014, the FERC issued its order in response to a complaint regarding the base ROE that New England electricity transmission owners are allowed to earn. The FERC reduced the base ROE to 10.57% effective October 16, 2014, down from the previous 11.14%. Although the lower ROE has reduced the revenues Transco collects through the ISO-NE Open Access Transmission Tariff, Transco's total revenue requirement will not be affected, as the reduction will instead be collected from Vermont utilities. However, this will place some rate pressure on the Vermont utilities and their customers, as they will have to contribute a larger portion of the 11.8% weighted-average return allowed for Transco's membership units.

4. Pipelines — Regulated by the National Energy Board (NEB) in Canada and by the FERC

Trans Québec Maritime Pipeline Inc. (TQM) — Regulated by the NEB

- TQM (50% owned; rated A (low) by DBRS) was under a multi-year rate agreement in which annual rates were calculated using a formula that includes a fixed-cost component, along with a cost-operating component that was fully recovered from or refunded to customers.
- In February 2014, TQM reached a multi-year settlement agreement with its interested parties, establishing the mechanisms for determining TQM's annual revenue requirements for 2014–2016.
- Under this agreement, annual rates are calculated, using a formula that includes a fixed-cost component and a component that is fully recoverable from or payable to customers.
- Refer to the TQM report dated November 13, 2015, for more details.

Champion Pipe Line Corporation Limited (Champion) — Regulated by the NEB

- This pipeline runs cross the Ontario border and supplies Gaz Métro's distribution system in Northern Québec.
- Champion (100% owned) is regulated by the NEB, with tolls based on an annual COS methodology.
- Champion uses a ROE and a capital structure equivalent to those approved by the Régie for Gaz Métro-QDA (the deemed equity component set at 46% and the authorized ROE at 8.9%).

Portland Natural Gas Transmission System (PNGTS)

- PNGTS (38.3% owned) originates at the Québec border and extends to suburbs of Boston.
- PNGTS is regulated by the FERC. The objective of the FERC is to ensure the recovery of costs expected to be incurred and a reasonable base ROE.

Assessment of Regulatory Environment

Gaz Métro-QDA — regulated by the Régie

Criteria	Score	Analysis
(1) Deemed Equity	Excellent **Good** Satisfactory Below Average Poor	Gaz Métro-QDA has a deemed equity of 46% (38.5% in common equity, 7.5% in preferred stock). With equity injections in F2015, Gaz Métro-QDA's actual capital structure is in line with its regulatory target (54% debt and 46% equity).
(2) Allowed ROE	Excellent Good **Satisfactory** Below Average Poor	The Régie agreed to not apply the automatic ROE adjustment formula and to set the ROE at 8.90% for F2016 and F2017 as it had done for F2014 and F2015. Gaz Métro-QDA has achieved its actual ROE close to the deemed ROE over the past several years.
(3) Energy Cost Recovery	**Excellent** Good Satisfactory Below Average Poor	There is no natural gas price risk for Gaz Métro-QDA as it is not responsible for purchasing natural gas from suppliers. Natural gas purchase costs are passed on to ratepayers at rates set by the Régie. Gaz Métro-QDA collects the payments from its customers on a monthly basis.
(4) Capital and Operating Cost Recovery	**Excellent** Good Satisfactory Below Average Poor	Major capital and operating costs are pre-approved by the Régie and recovered through distribution rates. Interim base-rate increases have been frequently authorized. Future test periods are fully incorporated for rate-case decisions.
(5) COS versus IRM	**Excellent** Good Satisfactory Below Average Poor	Gaz Métro-QDA expects to continue using the COS method until a new incentive mechanism is implemented, which is expected for F2018.
(6) Political Interference	Excellent **Good** Satisfactory Below Average Poor	There has been no adverse legislation in the regulated natural gas utility sector in Québec.
(7) Retail Rate	Excellent Good Satisfactory Below Average Poor	N/A
(8) Stranded Cost Recovery	Excellent **Good** Satisfactory Below Average Poor	Gaz Métro-QDA has a limited history of stranded costs.
(9) Rate Freeze	**Excellent** Good Satisfactory Below Average Poor	Rates have never been frozen and are not expected to be frozen in the foreseeable future.
(10) Market Structure (Deregulation)	**Excellent** Satisfactory Poor	The gas utility business has remained fully regulated under the Régie.

Vermont electricity and gas distribution utilities — regulated by the VPSB

Criteria	Score		Analysis
(1) Deemed Equity	Excellent / Good / Satisfactory / Below Average / Poor	**Excellent**	The VPSB allowed GMP and CVS to have a deemed equity of 50% and 55%, respectively for the 2015 period.
(2) Allowed ROE	Excellent / Good / Satisfactory / Below Average / Poor	**Good**	The VPSB set the authorized ROE at 9.6% for GMP and 10.20% for VGS for the 2015 period. With the cost overrun risk challenge facing VGS, its actual ROE is expected to below that of the authorized ROE in the near future. However, GMP has an opportunity to earn a higher actual ROE than that of the authorized ROE if GMP achieves its target merger savings.
(3) Energy Cost Recovery	Excellent / Good / Satisfactory / Below Average / Poor	**Satisfactory**	Revenue decoupling mechanisms are not in place. However, the VPSB allows power cost and purchased gas adjustments under an alternative regulation plan. GMP is allowed to recover 90% of the generation costs in excess of those included in rates on an annual basis. VGS is allowed to recover all purchased gas costs on a quarterly basis.
(4) Capital and Operating Cost Recovery	Excellent / Good / Satisfactory / Below Average / Poor	**Satisfactory**	Major capital and operating costs are pre-approved by the VPSB and recovered through rates. Interim base-rate increases are permitted; however, they have been rarely requested by utilities. Historical test periods are incorporated for rate-case decisions, resulting in regulatory lag. There is a reasonable mechanism to deal with cost overruns; however, utilities would share cost overrun risk with ratepayers, as evidenced by the Addison Natural Gas project in 2015.
(5) COS versus IRM	Excellent / Good / Satisfactory / Below Average / Poor	**Good**	GMP and VGS are regulated by the VPSB. Rates for their activities are established based on alternative regulation plans which is more similar to a traditional COS method than a typical longer-term performance-based regulation plan. The base rates are approved annually by the VPSB. Productivity factors and excess earning/cost-sharing mechanisms are reasonable.
(6) Political Interference	Excellent / Good / Satisfactory / Below Average / Poor	**Satisfactory**	Utilities are regulated by the VPSB, which operates as a quasi-judicial body. The Board is non-partisan and members are appointed to a six-year term.
(7) Retail Rate	Excellent / Good / Satisfactory / Below Average / Poor	**Below Average**	Average retail electricity rates were high at USD 17.12 cents/kWh (but the lowest in the New England region) in August 2015 (source: U.S. Energy Information Administration). However, natural gas purchase costs have remained low due to excess supply market conditions.
(8) Stranded Cost Recovery	Excellent / Good / Satisfactory / Below Average / Poor	**Good**	Utilities have a limited history of stranded costs.
(9) Rate Freeze	Excellent / Good / Satisfactory / Below Average / Poor	**Excellent**	Rates have never been frozen and are not expected to be frozen in the foreseeable future.
(10) Market Structure (Deregulation)	Excellent / Satisfactory / Poor	**Excellent**	The electricity and natural gas sectors have remained fully regulated.

Description of Operations

GMLP's operations are divided into the following sectors: Energy Distribution, Transportation of Natural Gas, Energy Production and Energy Services, Storage and Other. Under the Partnership Agreement, GMLP is not allowed to invest more than 10% of its total assets in non-regulated assets (on a non-consolidated basis).

1. Energy Distribution (87.5% of reported F2015 net income)

- GMLP's core business is natural gas distribution in Québec, delivering approximately 97% of the province's natural gas consumed and serving approximately 195,000 customers as of September 30, 2015.
- VGS is the sole gas distributor in Vermont.
- Green Mountain transports, distributes and sells electricity and provides electric network construction services in the State of Vermont. Following the acquisition and merger of Central Vermont Public Service Corporation, GMP is the largest electricity distributor in Vermont.

2. Natural Gas Transportation (8.5% of reported F2015 net income)

- TQM operates a gas pipeline in Québec that connects upstream with TCPL and downstream with PNGTS and the Gaz Métro-QDA system.
- In August 2015, GMLP signed an agreement with TCPL that ensures natural gas consumers in Eastern Canada will have sufficient capacity and reduce natural gas transmission costs should the Energy East Pipeline project (the 4,600-kilometre pipeline that will carry 1.1 million barrels of crude oil per day from Alberta and Saskatchewan to refineries in Eastern Canada) proceed.
- Champion operates two gas pipelines that cross the Ontario-Québec border to supply GMLP's distribution system in Northwestern Québec.
- PNGTS's pipeline originates at the Québec border and extends to the suburbs of Boston.

3. Energy Production (2.7% of reported F2015 net income)

- This segment consists of non-regulated energy production activities related to Wind Farms 2 and 3 and Wind Farm 4.
- Wind Farms 2 and 3 (total capital investment of $750 million including financing costs) are an equal-share joint venture of Boralex and Beaupré Éole, in which 51% is owned by the Partnership and the remaining 49% owned by Valener. As a result, GMLP owns 25.5% of the equity interest. GMLP received distributions in February 2015 and August 2015 for $40.6 million in aggregates.
- The joint venture's core business includes owning and operating wind farms with an installed capacity of 272 megawatts, which were commissioned in November 2013 and December 2013.
- Wind Farm 4 (total capital investment of $190 million including financing costs) is an equal share joint venture of Boralex and Beaupré Éole 4, in which 51% is owned by the Partnership and the remaining 49% owned by Valener. Wind Farm 4 owns and operates a wind farm with an installed capacity of 68 megawatts, which has been in service since December 2014. As a result, GMLP owns 25.5% of the equity interest. GMLP received its first distribution of $17.6 million in the fourth quarter of F2015.

4. Energy Services, Storage and Other (including non-regulated activities) (1.2% of reported adjusted F2015 net income)

- The Partnership owns an interest in the Intragaz Group, whose main activity is underground natural gas storage.
- This activity tallies with GMLP's mission, as the storage of natural gas in Québec is part of its supply chain.
- The Intragaz Group operates the only two underground storage facilities in Gaz Métro-QDA's service territory in Québec. GMLP is also its only customer. On May 17, 2013, the Régie approved COS as the method for setting rates, whereas previously the avoided-cost method had been used.
- Energy-related activities are focused on the maintenance and repair of residential, commercial and industrial equipment, the heating and cooling of large buildings, the sale of natural gas for heavy transport and the sale of LNG.

Gaz Métro Limited Partnership

Consolidated Balance Sheet

(CA$ millions)

Assets	Sept. 30 2015	2014	2013	Liabilities & Equity	Sept. 30 2015	2014	2013
				S.T. borrowings	35	5	23
Cash & equivalents	87	104	59	Current portion L.T.D.	33	27	90
Accounts receivable	223	212	223	Accounts payable	356	341	314
Inventories	118	115	93	Deferred tax	2	0	2
Others	73	83	35	Others	50	55	69
Total Current Assets	**500**	**514**	**410**	**Total Current Liabilities**	**476**	**428**	**499**
				Long-term debt (L.T.D.)	3,531	3,141	2,692
Net fixed assets	4,440	3,971	3,584	Other L.T. liabilities	1,005	788	684
Goodwill & intangibles	805	430	389	Deferred credits	376	305	264
Deferred charges	407	395	473	Minority interest	29	41	41
Investments & others	1,065	834	726	Shareholders equity	1,801	1,442	1,403
Total Assets	**7,218**	**6,144**	**5,583**	**Total Liab. & SE**	**7,218**	**6,144**	**5,583**

Gaz Métro Limited Partnership (consolidated)

Balance Sheet & Liquidity & Capital Ratios	For the year ended September 30th 2015	2014	2013	2012	2011
Current ratio	1.05	1.20	0.82	0.70	0.76
Net debt in capital structure	65.7%	67.4%	65.5%	64.6%	63.0%
Total debt in capital structure	66.3%	68.2%	66.0%	65.0%	63.5%
Total debt in capital structure 1, 2	67.2%	67.9%	65.3%	63.7%	62.1%
Cash flow/Net debt	16.2%	15.0%	13.0%	13.4%	18.6%
Cash flow/Total debt	15.8%	14.5%	12.7%	13.1%	18.3%
Cash flow/Total debt 1	15.7%	14.4%	12.6%	13.0%	18.2%
Cash flow-interest coverage	4.21	3.87	3.50	3.87	4.23
(Cash flow - dividends)/Capex	0.49	0.62	0.40	0.39	1.01
Distribution payout ratio	97.0%	96.8%	99.7%	93.3%	72.0%
Coverage Ratios (times)					
EBIT gross interest coverage	1.81	1.84	1.81	2.10	2.42
EBITDA gross interest coverage	3.34	3.39	3.24	3.53	4.18
Fixed-charge coverage	1.81	1.84	1.81	2.10	2.42
Debt/EBITDA	6.07	5.85	6.09	6.19	4.24
EBIT gross interest coverage 1	1.82	1.85	1.83	2.11	2.42
Profitability Ratios					
Return on equity	11.7%	11.6%	11.3%	12.1%	14.3%
Return on capital	6.3%	6.4%	6.3%	6.8%	7.6%
Deemed common equity (Gaz Métro-QDA)	38.5%	38.5%	38.5%	38.5%	38.5%
Allowed base ROE (Gaz Métro-QDA)	8.90%	8.90%	8.90%	9.69%	9.09%

1 Adjusted for operating leases. 2 Adjusted for accumulated other comprehensive income.

Rating History

	Current	2014	2013	2012	2011	2010
Issuer Rating	A	A	A	A	NR	NR
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
First Mortgage Bonds*	A	A	A	A	A	A
Senior Secured Notes*	A	A	A	NR	NR	NR

* Guaranteed by Gaz Métro Limited Partnership

Previous Action

- DBRS Confirms Gaz Métro inc. at "A," Stable, January 23, 2015

Related Research

- DBRS Confirms Gaz Métro inc. at R-1 (low), Stable Trend, with CP Limit Increase, December 2, 2015
- DBRS Rates Gaz Métro inc.'s CAD 100 million First Mortgage Bonds at "A," Stable, March 31, 2015

Commercial Paper Limited

- $800 million

Previous Report

- Gaz Métro inc., January 30, 2015

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on **www.dbrs.com**.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

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Rating Report

Nova Scotia Power Inc.

DBRS

Insight beyond the rating.

Andy Thi
+1 416 597 7337
athi@dbrs.com

James Jung, CFA, FRM, CMA
+1 416 597 7577
jjung@dbrs.com

Moritz Steinbauer
+1 416 597 7494
msteinbauer@dbrs.com

Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A (low)	Confirmed	Stable
Unsecured Debentures & Medium-Term Notes	A (low)	Confirmed	Stable
Cumulative Preferred Shares	Pfd-2 (low)	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating Update

DBRS Limited (DBRS) has confirmed the ratings of Nova Scotia Power Inc. (NSPI or the Company) as listed above. The rating confirmations reflect the Company's relatively low business risk profile operating under a reasonable regulatory environment in Nova Scotia (the Province), albeit somewhat below average compared to other provinces that have privatized or deregulated their power sectors. The confirmations also reflect NSPI's reasonable financial risk profile, with all key credit metrics expected to remain in line with the current rating category and within regulatory parameters.

Over the past year, there has been no material changes to NSPI's business risk profile, which remains commensurate with the current rating category. In 2015, NSPI continues to operate under a reasonable regulatory system that allows the company to earn a return on equity (ROE) in the range of 8.75% to 9.25%, based on an equity thickness of up to 40% (actual ROE has historically been in the upper-end of the target ranges). NSPI's current business risk rating, which is one-notch below that of the DBRS industry risk rating of "A", factors in the Company's below-average regulatory lag compared to domestic peers, particularly related to its fuel cost recovery. Fuel costs are also subject to an independent audit by the Nova Scotia Utility and Review Board (UARB), which could potentially disallow a portion of the fuel-related costs. In January 2015, the UARB disallowed $5.1 million of 2012 and 2013 fuel-related costs (before interest); however, this amount is not considered material by DBRS. The Company's business risk profile also reflects the challenges associated with the Province's high electricity rates, which may make it increasingly challenging for NSPI to fully pass costs onto the ratepayers in a timely manner if generation costs rise faster than anticipated. Going forward, should significant fuel-related costs be disallowed, and/or if substantial costs are not recovered or could only be recovered over an extended period of time, this could have a negative impact on NSPI's credit quality.

NSPI's financial risk profile remained reasonable for the current rating and is expected to remain relatively stable, with all key credit metrics in the "A" rating range. In 2015, operating cash flow should sufficiently support the Company's capital expenditures (capex) program ($273 million announced for 2015). NSPI is expected to continue to manage its dividend payout to its parent company, Emera Inc. (Emera; rated BBB (high), Under Review with Developing Implications) in order to maintain its debt-to-capital ratio within regulatory parameters. DBRS will continue to view NSPI on a stand-alone basis, assuming the Company adheres to the current flexible dividend distribution strategy.

Financial Information

	For the year ended December 31				
(CA$ millions)	2014	2013	2012	2011	2010
EBIT gross interest coverage	2.19	2.25	1.75	1.67	2.04
Total debt in capital structure 1	61.2%	60.8%	61.2%	58.0%	60.3%
Cash flow/Total debt 2	15.8%	15.5%	14.7%	15.2%	12.7%
Net income before non-recurring items	133	134	134	132	139
Cash flow from operations 2	365	349	331	308	253

1 Including operating leases and adjustments for accumulated other comprehensive income. 2 Adjusted for a one-time voluntary $90M pension contribution in 2012.

Issuer Description

Nova Scotia Power Inc. is a fully integrated, regulated electricity utility that generates, transmits and distributes electricity in the Province of Nova Scotia. The Company is wholly owned by Emera Inc. (rated BBB (high), Under Review Developing Implications), which is a diversified energy and energy-services holding company listed on the Toronto Stock Exchange.

Rating Considerations

Strengths

1. Reasonable regulatory regime
The current regulatory framework is based on a cost of service methodology, in which the Company is allowed to recover all prudently estimated operating expenses and earn a reasonable return on approved capital investments. NSPI's target ROE range of 8.75% and 9.25% for 2015 is also viewed as reasonable and in line with those of other Canadian utilities.

2. Good financial profile
Overall, the Company has maintained a good financial profile, reflecting reasonable credit metrics for the current rating. All three key credit metrics for the 12 months ended December 31, 2014, remained within DBRS's "A" rating category.

3. Good franchise strength
NSPI has a virtual monopoly on electricity service throughout the Province, providing over 95% of its electricity generation, transmission and distribution. The Company's rate base and earnings are also expected to grow favourably in the medium to long term with its continued investment in renewable generation and infrastructure improvements.

Challenges

1. Unfavourable generation mix
As a result of the current generation mix, NSPI is dependent on international suppliers for its fuel supply, exposing the Company to volatile global pricing. This, combined with continued investments in renewable energy, has contributed to higher than average electricity retail rates among Canadian provinces. Higher electricity rates could make it increasingly challenging for NSPI to fully pass costs on to the ratepayers in a timely manner.

2. Regulatory lag
NSPI faces some regulatory risk (albeit lower than when the fuel adjustment mechanism (FAM) was not in place) with respect to the timeliness of full cost recovery. It is expected that the difference between the costs included in the rates and the actual costs of fuel will be deferred, refunded to or collected from customers in a subsequent year.

3. Limited access to equity markets
NSPI has limited access to equity markets to fund any free cash flow deficits. As such, DBRS expects Emera to continue to support NSPI's capital expenditure program with its flexible dividends policy and equity injections, if needed.

Earnings and Outlook

(CA$ millions)	2014	2013	2012	2011	2010
	For the year ended December 31				
Net revenues	837	778	742	686	605
Fuel cost 1	512	557	495	547	587
Operating costs	359	269	308	299	187
EBITDA	478	509	435	387	418
EBIT	274	295	222	200	230
Gross interest expense	125	131	127	120	112
Net income before non-recurring items	133	134	134	132	139
Reported net income	133	134	134	131	127
Return on avg. equity 2	9.1%	9.2%	9.2%	9.5%	10.8%
Regulated rate base	3,676	3,682	3,659	3,470	3,299
Actual regulated return on equity (%)	9.25%	9.24%	9.40%	9.60%	9.60%

1 Before fuel adjustment. 2 Includes adjustments for accumulated other comprehensive income.

2014 Summary

- NSPI's EBIT was negatively impacted by the FAM audit disallowance and lower sales volume, which was slightly offset by the effects of the net rate increase for the year.
- Earnings before non-recurring items remained relatively flat, benefiting from lower interest expense.
- NSPI continues to earn within its target ROE range of 8.75% to 9.25%

2015 Outlook

- Earnings in 2015 are expected to benefit from a modest increase in rate base, with actual ROE expected to continue to be within the target ROE range.
- Growth of the rate base over the medium term, driven by the Company's continued investment in renewable generation and infrastructure improvements, could increase earnings gradually.

Financial Profile

(CA$ millions)	2014	2013	2012	2011
	For the year ended December 31			
Net income before non-recurring items	133	134	134	132
Depreciation & amortization	212	225	227	201
Deferred income taxes and other	20	(11)	(29)	(25)
Cash flow from operations 2	365	349	331	308
Dividends paid	(128)	(108)	(169)	(33)
Capital expenditures	(267)	(194)	(260)	(303)
Free cash flow (bef. working cap. changes)	(30)	47	(97)	(28)
Changes in non-cash work. cap. items	(30)	(23)	(27)	(35)
Adjustment for regulated assets and liabilities	0	0	0	0
Net Free Cash Flow	(59)	24	(124)	(63)
Acquisitions & long-term investments	0	0	0	0
Proceeds on asset sales	8	0	0	0
Net equity/preferred change	1	0	0	50
Net debt change	62	(10)	232	27
Other 2	(11)	(14)	(108)	(15)
Change in cash	0	0	0	(0)
Total debt in capital structure 1	61.2%	60.6%	61.2%	58.0%
Cash flow/Total debt 2	15.8%	15.5%	14.7%	15.2%
EBIT gross interest coverage (times)	2.19	2.25	1.75	1.67
Dividend payout ratio	96.3%	80.6%	126.1%	24.9%

1 Including operating leases and adjustments for accumulated other comprehensive income. 2 Adjusted for a one-time voluntary $90M pension contribution in 2012.

2014 Summary

- NSPI's key credit metrics remained reasonable for the current rating, with all three key credit metrics remaining within DBRS's "A" rating range.
- In 2014, NSPI generated a modest free cash flow deficit as slightly higher operating cash flows were more than offset by higher dividends and capex during the period. The free cash flow deficit was primarily funded with debt, and proceeds from a minor asset divestiture ($8 million).
- Capex increased significantly during the year primarily due to the construction of the South Canoe Wind Farm (South Canoe; expected completion in 2015) and Sable Wind Farm (commenced operations in December 2014). Capex was in line with prior year's forecasts.
- The Company manages its annual dividend payout to stay within its regulatory capital structure. NSPI is expected to maintain a reasonably stable debt-to-capital ratio of around 60%, which is in line with the regulatory capital structure.

2015 Outlook

- DBRS expects the Company's key credit metrics to continue to remain within its current rating range in the short to medium term.
- NSPI has forecast total gross capex for 2015 of $273 million. Approximately 41% is budgeted for its generation segment (including approximately $12 capex remaining for South Canoe), while capex relating to the transmission and distribution segments are expected to increase modestly relative to 2014.
- Operating cash flow is estimated to be adequate to support this level of capex. DBRS expects that residual operating cash flow after capex, combined with the incremental debt to maintain the regulatory capital structure, will be distributed to Emera.
- DBRS expects Emera to continue to support NSPI's capital expenditure program with its flexible dividends policy and equity injections, if needed.
- Over the medium term, DBRS expects the Company to continue to invest in renewable energy and related infrastructure, with the capital spending being recoverable after the projects have been included in the rate base.

Long-Term Debt and Liquidity

Long-term debt maturities

(CAD$ Million - As at Dec. 31, 2014)	2015	2016	2017	2018	2019	Thereafter	Total
Total Amount	70.5	0.3	0.1	0.1	444.1	1,790.0	2,305.1
Unamortized Issue Costs for LTD	-					0.4	0.4
Total Long-term Debt *	**70.5**	**0.3**	**0.1**	**0.1**	**444.1**	**1,790.4**	**2,305.5**
*Including credit facilities	3%	0%	0%	0%	19%	78%	

Liquidity

(CAD$ Million - As at Dec. 31, 2014)	Amount	Drawn	Available
Cash & Cash equivalents	0	0	0
Committed Revolving Facilities	500	350	150
Total	**500**	**350**	**150**

- The Company has a $400 million commercial paper program that is 100% backed by a revolving credit facility which matures in June 2019. The maturity of the revolving credit facility was extended in November 2014 to June 2019.
- As of December 31, 2014, $350 million of the total credit facility amount was outstanding and was classified under long-term debt for financial reporting purposes by the Company.
- DBRS believes that the facilities will provide sufficient liquidity to finance the Company's ongoing operating needs.

Summary of Debt

- Based on the Company's good financial risk profile and debt maturity profile, the Company's near-term refinancing risk remains modest and manageable. The Company has approximately $70 million maturing in 2015 (3.0% of total long-term debt outstanding) and a revolving credit facility maturing in 2019.
- The Company currently has a debenture covenant stating that NSPI will not incur funded debt if its funded debt would be in excess of 75% of total capitalization. NSPI also has a financial covenant with its credit facility of a debt-to-capital ratio of 0.65 to 1.00. The covenants are not expected to restrict NSPI's operations going forward or pose any challenges in the near to medium term.

Regulation

- NSPI operates under a reasonable regulatory environment of the UARB, using a cost-of-service methodology, which allows the Company to recover all prudently estimated operating expenses and earn a reasonable return on approved capital investments.
- NSPI's target ROE range for 2014 and 2015 was approved to be between 8.75% and 9.25%, based on the maximum 40% regulated common equity component. NSPI did not file a general rate application (GRA) related to electricity rates for 2015.
- On December 21, 2012, UARB issued an approved average net rate increase of 3.0% by customer class, effective January 1, 2013, and again on January 1, 2014. Rates were calculated based on a 9.0% ROE and on a common equity component of 37.5%.
  - The UARB also approved a deferral mechanism where the amounts deferred to achieve the average net 3.0% increases in 2013 and 2014 would be deferred to 2015. This includes the unrecovered or over-recovered fuel costs amounts in 2013 (normally recovered in 2014).
  - On December 2, 2014, the UARB directed NSPI to transfer the balance in the rate stabilization deferral liability of $38.2 million to reduce against the FAM balance.
  - On December 2, 2014, through a settlement agreement with stakeholders, NSPI will reduce the FAM deferral account by any revenues greater than the target ROE range from 2015 until the next GRA approval. This settlement agreement requires NSPI to contribute a minimum of $41.3 million to the FAM deferral account by the end of 2015. A total of $3.1 million remains for 2015 as $38.2 million of the balance has been contributed from 2013 and 2014 earnings above the target ROE range.
- Subject to an independent audit, differences between actual fuel costs and fuel costs recovered are deferred to a FAM regulatory asset or liability and recovered from or returned to the customers in a subsequent year.
  - On November 25, 2014, the UARB approved a settlement agreement that is expected to result in approximately $56 million of the outstanding FAM balance to be collected in 2015.
  - On December 2, 2014, the UARB directed NSPI to transfer the remaining $38.2 million of the liability balance of the rate stabilization deferral account to reduce the FAM balance. As such, this results in a revised FAM regulatory asset balance of $47.9 million as at December 31, 2014.
  - On January 20, 2015, the UARB disallowed $5.1 million of 2012 and 2013 fuel-related costs (before interest). Although the decision will have a modest impact on earnings and cash flow, it is not considered material.
  - DBRS expects that under FAM, NSPI will recover all of its prudently incurred fuel costs (including carrying charges) from its customers over the deferral period and will continue to monitor future FAM filings. If significant fuel-related costs are disallowed, this could have a negative impact on NSPI's credit quality.
- The shortfall in contributions toward non-fuel charges incurred in 2012 that were associated with the NewPage Port Hawkesbury paper mill and the Bowater Mersey facility, which were eventually shut down in 2012, was deferred for future recovery by the UARB. Charges will be recovered from customers over a three-year period commencing January 1, 2013. As at December 31, 2014, the balance of this regulatory asset is approximately $15.8 million, which is expected to be fully collected in 2015.
- In December 2013, the Province approved the Electricity Reform (2013) Act, which will allow licensed renewable generators to sell directly to retail customers in the Province by 2015.
  - Following the legislation of this act, NSPI will be required to develop related tariffs for distribution and transmission and standards of conduct for approval by the UARB this year.
  - DBRS does not expect this act to result in a significant increase in competition or have a material impact on NSPI's credit quality. It will likely be challenging for new entrants to successfully compete against NSPI, the Province's incumbent utility. In addition, NSPI will still receive related tariffs for its distribution and transmission services.
- In April 2014, the Province announced new energy efficiency legislation that requires NSPI to purchase electricity efficiency and conservation activities from Efficiency Nova Scotia when the costs are lower than generation on a go-forward basis. Costs are capped at $35 million for 2015, with costs being deferred as a regulatory asset and recoverable from customers over an eight year period beginning in 2016. The UARB will provide regulatory oversight of the costs thereafter.
- The chart that follows reflects DBRS's assessment of the regulatory environment for NSPI, based on ten separate factors. For further details, please refer to Appendix A in the DBRS methodology *Rating Companies in the Regulated Electric, Natural Gas and Water Utilities Industry.*

Regulation (CONTINUED)

Factors	Score	Analysis
Deemed Equity	Excellent Good **Satisfactory** Below Average Poor	NSPI has a maximum 40% regulated common equity threshold.
Allowed ROE	Excellent **Good** Satisfactory Below Average Poor	NSPI's rates were calculated based on a 9.0% ROE. Its target ROE range for 2014 and 2015 was approved to be between 8.75% and 9.25%
Energy Cost Recovery	Excellent Good Satisfactory **Below Average** Poor	Fuel costs are passed through to the customers through FAM, but deferred to the subsequent year. In addition, fuel costs are subject to an independent audit by the UARB, which could potentially disallow a portion of fuel-related costs.
Capital Cost Recovery	**Excellent** Good Satisfactory Below Average Poor	Capital costs are pre-approved by the regulator and construction work-in-progress costs can be added to the rate base.
Cost of Service vs. Incentive Regulation Mechanism	Excellent **Good** Satisfactory Below Average Poor	NSPI is regulated under a cost of service model, which allows the Company to recover all prudently estimated operating expenses and earn a reasonable return on approved capital investments. However, the last rate settlement in December 2012 established a productivity target of $27.5 million over two years for non-fuel costs.
Political Interference	Excellent Good Satisfactory **Below Average** Poor	The Province's introduction of the Electricity Reform Act and Energy Efficiency Legislation reflects some of its direct, but modest impact on NSPI.
Retail Rate	Excellent Good Satisfactory **Below Average** Poor	The retail residential electricity rates in the Province are higher than the average among Canada's provinces. This could make it challenging for NSPI to pass all costs on to ratepayers in a timely manner.
Stranded Cost Recovery	Excellent **Good** Satisfactory Below Average Poor	The recovery of some fuel-related costs has been disallowed by the UARB; however, the amount is not material.
Rate Freeze	Excellent **Good** Satisfactory Below Average Poor	Rates have the potential to be frozen going forward based on political risks. This would expose NSPI to increases in operating and energy costs. However, NSPI has not experienced a rate freeze in recent years.
Market Structure (Deregulation)	**Excellent** Satisfactory Poor	The market is fully regulated and NSPI is a fully integrated utility.

Description of Operations

- NSPI is the primary electricity supplier in Nova Scotia, providing over 95% of electricity generation, transmission and distribution in the Province. The Company has approximately 504,000 customers.
- The Company owns approximately 2,483 megawatts (MW) of generating capacity. Approximately 50% is coal-fired, with oil and natural gas together comprising another 28%, and hydro, biomass and wind production providing the remainder. NSPI also purchases renewable energy from independent power producers through long-term contracts, who own 314MW of wind and biomass-fueled generation capacity (increasing to 376 MW in 2015).
- NSPI's strategy is to continue to increase its generation from renewable sources over the medium term.
- NSPI transmits and distributes electricity from its generating plants to its customers.
  - Its transmission system consists of approximately 5,000 kilometres of transmission lines, including major substations connected solely to transmission lines and its distribution system.
  - The distribution system consists of approximately 27,000 kilometres of distribution lines and a distribution supply substation.
- The Company is a wholly owned subsidiary of Emera Inc.

Pension Status

- In 2012, NSPI made a one-time, voluntary contribution of $90 million to its defined benefit pension plan. This was in addition to the minimum contribution required by legislation and it improved the funded status for the year.
- As of December 31, 2014, NSPI had a funded status of 83%, versus 85% in 2013 and 69% in 2012. The funded status declined modestly primarily due to a lower discount rate assumption for the defined benefit obligation (4.00% in 2014, versus 5.00% in 2013).
- DBRS views 80% as a level where funding is considered adequate, noting the long-term and somewhat volatile nature of a company's funded status.
- At the 80% level, changes in performance, contributions and other factors, such as discount rates, can typically bring a plan up to strong levels relatively quickly. When funding is below 80%, the funding challenges become more formidable.

Operating Statistics

		For the year ended December 31				
		2014	2013	2012	2011	2010
Electricity Sold						
Residential	42%	4,370	4,394	4,186	4,275	4,147
Commercial	30%	3,092	3,148	3,099	3,102	3,089
Industrial	24%	2,513	2,605	2,167	3,516	3,908
Other (including exports)	3%	312	320	337	313	312
Total (GWh sold)		10,287	10,467	9,789	11,206	11,455
Energy sales growth		-2%	7%	-13%	-2%	1%
Installed Generation Capacity						
Coal	50%	1,243	1,243	1,243	1,243	1,243
Hydro	16%	395	395	395	395	395
Dual fuel	14%	350	350	350	350	350
Gas turbine	14%	353	353	353	304	304
Wind	3%	82	82	82	82	76
Biomass	2%	60	60	0	0	0
Installed capacity (megawatts)		2,483	2,483	2,423	2,374	2,368
Long-term IPP contracts (MW)		314	273	265	229	186
Energy generated – GWh						
Coal	67%	6,609	7,098	6,223	6,848	7,839
Natural gas	15%	1,468	1,317	2,158	2,430	2,275
Oil	2%	153	89	12	35	36
Hydro, wind and biomass	16%	1,615	1,364	1,084	1,335	1,017
Gross energy generated		9,845	9,868	9,477	10,648	11,167
Plus: purchases		1,202	1,337	1,032	1,269	997
Energy generated + purchased		11,047	11,205	10,509	11,917	12,164
Less: transmission losses & internal use		760	737	720	711	709
Total (GWh sold)		10,287	10,467	9,789	11,206	11,455

Nova Scotia Power Inc.

Balance Sheet

(CA$ millions)	December 31				December 31		
Assets	**2014**	**2013**	**2012**	**Liabilities & Equity**	**2014**	**2013**	**2012**
Cash & equivalents	0	0	0	S.T. borrowings	2	7	8
Accounts receivable	258	255	219	Accounts payable	125	109	107
Inventories	199	164	132	Current portion L.T.D.	71	0	300
Prepaid expenses & other	128	66	142	Deferred tax	12	0	2
				Other current liab.	156	146	123
Total Current Assets	585	485	493	**Total Current Liab.**	365	262	541
Net fixed assets	3,276	3,185	3,157	Long-term debt	2,235	2,239	1,949
Future income tax assets	0	0	0	Provisions	341	279	477
Goodwill & intangibles	79	78	74	Other L.T. liab.	298	277	111
Investments & others	385	440	230	Preferred shares	132	132	132
				Common equity	953	997	744
Total Assets	**4,324**	**4,187**	**3,954**	**Total Liab. & SE**	**4,324**	**4,187**	**3,954**

Balance Sheet & Liquidity & Capital Ratios

	For the year ended December 31				
	2014	**2013**	**2012**	**2011**	**2010**
Current ratio	1.60	1.85	0.91	1.53	1.34
Total debt in capital structure 1, 2	61.2%	60.6%	61.2%	58.0%	60.3%
Cash flow/Total debt 3	15.8%	15.5%	14.7%	15.2%	12.7%
(Cash flow-dividends)/Capex 3	0.89	1.24	0.63	0.91	0.27
Dividend payout ratio	96.3%	80.6%	126.1%	24.9%	77.4%
Coverage Ratios (times)					
EBIT gross interest coverage	2.19	2.25	1.75	1.67	2.04
EBITDA gross interest coverage	3.81	3.88	3.43	3.23	3.72
Fixed-charge coverage	2.02	2.09	1.63	1.54	1.94
Profitability Ratios					
EBITDA margin	57.1%	65.4%	58.6%	56.4%	69.1%
EBIT margin	32.8%	37.9%	30.0%	29.1%	38.0%
Profit margin	15.9%	17.2%	18.0%	19.3%	23.0%
Return on avg. equity 2	9.1%	9.2%	9.2%	9.5%	10.8%
Return on avg. capital 1, 2	5.8%	6.0%	6.0%	6.1%	6.5%

1 Including operating leases. 2 Includes adjustments for accumulated other comprehensive income. 3 Adjusted for a one-time voluntary $90M pension contribution in 2012.

	For the year ended December 31				
	2014	**2013**	**2012**	**2011**	**2010**
Earnings Quality/Operating Efficiency					
Fuel for generation and purchase power/Revenues	38.0%	41.7%	40.0%	44.4%	49.2%
EBIT margin	32.8%	37.9%	30.0%	29.1%	38.0%
Profit margin	15.9%	17.2%	18.0%	19.3%	23.0%
Return on avg. equity 1	9.1%	9.2%	9.2%	9.5%	10.8%
Approved ROE - mid-point	9.00%	9.00%	9.00%	9.35%	9.35%
Customers/Employee	294	289	261	262	258
Growth in customer base	0.6%	0.7%	0.9%	0.8%	0.8%
GWh sold/Employee	6.01	6.03	5.14	5.95	6.03
Self-Generation (Cost Structure)					
OM&A	3.01	2.98	2.97	2.70	2.35
Fuel for generation and purchased power	5.63	6.10	5.65	5.51	5.61
Variable costs	8.64	9.08	8.62	8.21	7.96
Government levies	0.42	0.41	0.43	0.39	0.38
Gross interest expense	1.38	1.43	1.45	1.20	1.07
Total cash costs	10.45	10.93	10.50	9.81	9.42
Non-cash financial charges	0.02	0.04	(0.04)	0.01	0.04
Depreciation & amortization	2.25	2.34	2.42	1.88	1.80
Total costs (Excl. income taxes)	**12.71**	**13.32**	**12.88**	**11.70**	**11.26**
Number of Customer Accounts					
Residential	456,285	453,460	450,366	446,379	442,824
Commercial	35,560	35,402	35,169	34,998	34,864
Industrial	2,395	2,426	2,449	2,462	2,485
Other	9,436	9,430	9,394	9,344	9,256
Total	**503,676**	**500,718**	**497,378**	**493,183**	**489,429**
Employees	1,713	1,735	1,906	1,883	1,900
Rate Base ($ millions) 3	3,676	3,682	3,659	3,470	3,299
Total fixed costs					
Net generated electricity	9,085	9,130	8,757	9,937	10,456
Net purchased electricity	1,202	1,337	1,032	1,269	997

1 Including adjustments for accumulated other comprehensive income. 2 Before fuel adjustment. 3 2010 figure was prepared under CGAAP.

Rating History

	Current	2014	2013	2012	2011	2010
Issuer Rating	A (low)	A (low)	A (low)	NR	NR	NR
Unsecured Debentures & Medium-Term Notes	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)
Cumulative Preferred Shares	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)

Previous Report

- Nova Scotia Power Inc., Rating Report, February 18, 2014.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on **www.dbrs.com**.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

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