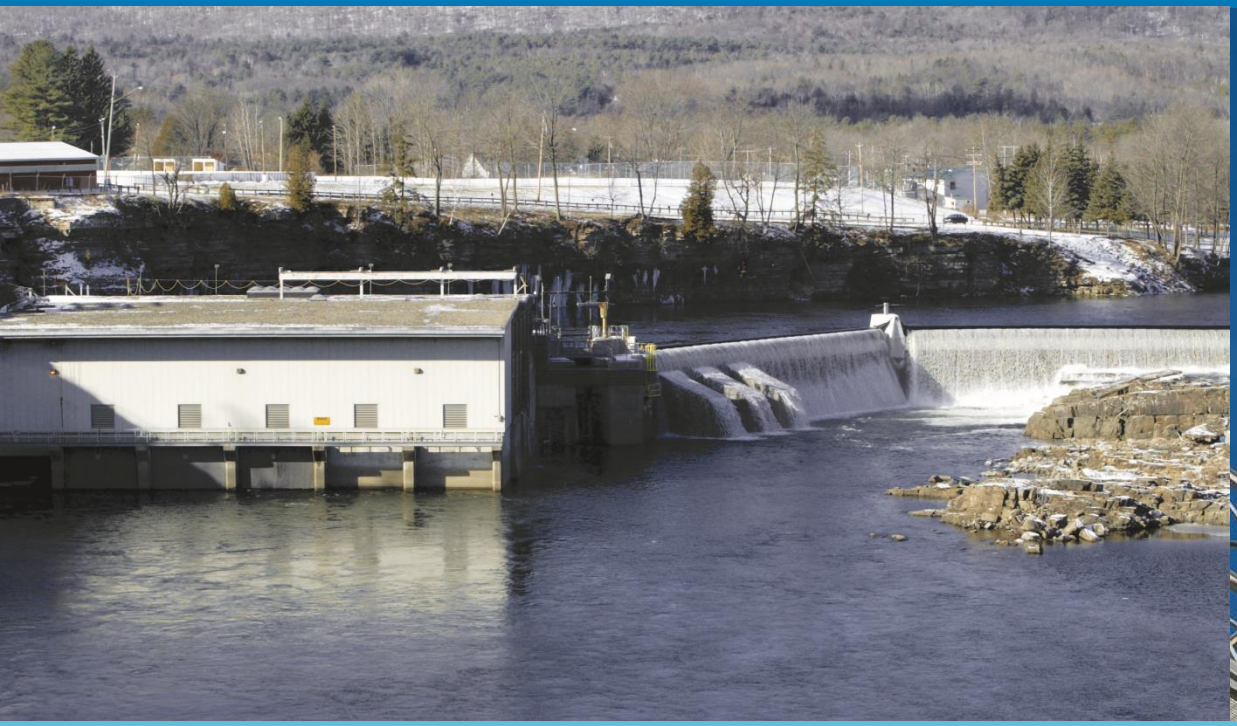
AtlanticPower Corporation



Q4 and FY 2016 Financial Results Conference Call

March 3, 2017

Cautionary Note Regarding Forward-Looking Statements

To the extent any statements made in this presentation contain information that is not historical, these statements are forward-looking statements or forward-looking information, as applicable, within the meaning of Section 27A of the U.S. Securities Act of 1933, as amended, and Section 21E of the U.S. Securities Exchange Act of 1934, as amended, and under Canadian securities law (collectively "forward-looking statements").

Forward-looking statements can generally be identified by the use of words such as "should," "intend," "may," "expect," "believe," "anticipate," "estimate," "continue," "plan," "project," "will," "could," "would," "target," "potential" and other similar expressions. In addition, any statements that refer to expectations, projections or other characterizations of future events or circumstances are forward-looking statements. Although Atlantic Power Corporation ("AT", "Atlantic Power" or the "Company") believes that the expectations reflected in such forward-looking statements are reasonable, such statements involve risks and uncertainties and should not be read as guarantees of future performance or results, and undue reliance should not be placed on such statements. Please refer to the factors discussed under "Risk Factors" and "Forward-Looking Information" in the Company's periodic reports as filed with the Securities and Exchange Commission from time to time for a detailed discussion of the risks and uncertainties affecting the Company, including, without limitation, the outcome or impact of the Company's business plan, including the objective of enhancing the value of its existing assets through optimization investments and commercial activities, delevering its balance sheet to improve its cost of capital and ability to compete for new investments, and utilizing its core competencies to create proprietary investment opportunities, and the Company's ability to raise additional capital for growth and/or debt reduction, and the outcome or impact on the Company's business of any such actions. Although the forward-looking statements contained in this presentation are based upon what are believed to be reasonable assumptions, investors cannot be assured that actual results will be consistent with these forward-looking statements, and the differences may be material. These forward-looking statements are made as of the date of this presentation and, except as expressly required by applicable law, the Company assumes no obligation to update or revise them to reflect new events or circumstances. The Company's ability to achieve its longer-term goals, including those described in this presentation, is based on significant assumptions relating to and including, among other things, the general conditions of the markets in which it operates, revenues, internal and external growth opportunities, its ability to sell assets at favorable prices or at all and general financial market and interest rate conditions. The Company's actual results may differ, possibly materially and adversely, from these goals.

Disclaimer – Non-GAAP Measures

Project Adjusted EBITDA is not a measure recognized under GAAP and does not have a standardized meaning prescribed by GAAP, and is therefore unlikely to be comparable to similar measures presented by other companies. Investors are cautioned that the Company may calculate this non-GAAP measure in a manner that is different from other companies. The most directly comparable GAAP measure is Project income (loss). Project Adjusted EBITDA is defined as project income (loss) plus interest, taxes, depreciation and amortization (including non-cash impairment charges) and changes in the fair value of derivative instruments. Management uses Project Adjusted EBITDA at the project level to provide comparative information about project performance and believes such information is helpful to investors. A reconciliation of Project Adjusted EBITDA to Project income (loss) and to Net income (loss) by segment and on a consolidated basis is provided on slides 42-43.

Cash Distributions from Projects is the amount of cash distributed by the projects to the Company out of available project cash flow after all project-level operating costs, interest payments, principal repayment, capital expenditures and working capital requirements. It is not a non-GAAP measure. Project Adjusted EBITDA, a non-GAAP measure, is the most comparable measure, but it is before debt service, capital expenditures and working capital requirements. The Company has provided a bridge of Project Adjusted EBITDA to Cash Distributions from Projects on slides 39-40.

All amounts in this presentation are in US$ and approximate unless otherwise stated.

Agenda

- CEO: 2016 Progress Report
- Operations Review
- Commercial Review / PPAs
- 2016 Financial Results
- Balance Sheet and Liquidity Update
- 2017 Guidance
- CEO: Year End Review and Outlook
- Q&A

2016 Progress Report

Reducing leverage and reshaping maturity profile

- Refinanced term loan and revolver, gaining flexibility and extended maturity dates
  - $252 million net increase in debt was mostly offset by other debt repayment
- Net reduction in debt of $22 million; leverage ratio [1] of 5.6x at December 31, 2016
- Expect to repay approximately $150 million or more in 2017, achieving year end leverage ratio of approximately 4x
- No corporate debt maturities until June 2019

Improving cost structure

- Further reduction in cash interest payments; now $60 million lower than 2013 (46%)
- G&A expense down 28% in 2016 to $23 million; now $31 million lower than 2013 (58%)

Liquidity of $204 million

- Includes approximately $50 million of discretionary cash

Financial results

- Cash provided by operating activities of $112 million, in line with expectations
- Project Adjusted EBITDA of $202 million, below guidance due to lower water flows at Curtis Palmer, lower waste heat and severance expense at three Ontario projects

[1] Consolidated gross debt to trailing 12-month consolidated Adjusted EBITDA (after Corporate G&A)

2016 Progress Report (cont'd)

Completed major projects in optimization program

- Investing a total of approximately $27 million from 2013 projected through 2017
- Expect a cash return in 2017 of approximately $12 million

Repurchased and canceled 6.6% of shares outstanding

- Slightly less than 8.1 million common shares since December 2015
- Total investment of $19.6 million (average price of $2.42 per share)

Initiated 2017 guidance for Project Adjusted EBITDA of $225 to $240 million

- Significant increase from 2016 level, primarily driven by expiration of above-market gas supply contract (Ontario)

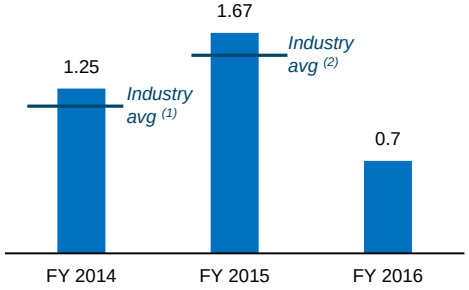
Stronger financial position, improved cost profile and increased liquidity put Company in a better position to withstand extended downturn in a highly cyclical business and:

- Pay down additional debt
- Repurchase shares at discount to our estimate of intrinsic value
- Work toward PPA renewals
- Begin to implement a growth strategy

Q4 2016 Operational Performance:

Lower availability due to outages in the current period; lower generation driven by lower demand at Frederickson and lower water flow at Curtis Palmer

Safety: Total Recordable Incident Rate



(1) 2014 BLS data, generation companies = 1.1
(2) 2015 BLS data, generation companies = 1.4

Availability (weighted average)

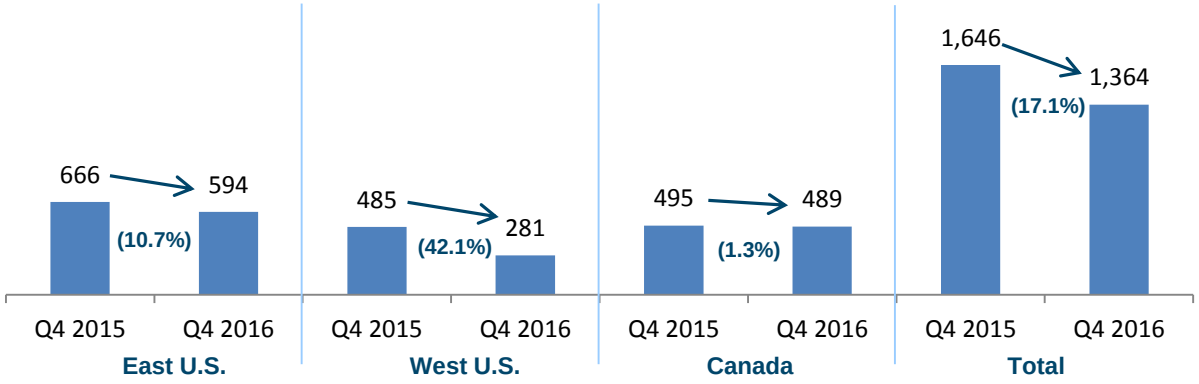
	Q4 2016	Q4 2015
East U.S.	92.6%	98.0%
West U.S.	91.2%	94.1%
Canada	96.3%	93.5%
Total	**93.0%**	**96.0%**

Availability factor down:

– Maintenance outages in Q4 2016 at Kenilworth, Selkirk and NTC (only modest impact on Project Adjusted EBITDA)

\+ Shorter fall outages at Piedmont and Mamquam

Aggregate Power Generation Q4 2016 vs. Q4 2015 (thousands, Net MWh)



Generation down 17.1% year-on-year:

– Frederickson, lower dispatch due to mild weather and higher availability of hydro plants in the region

– Curtis Palmer, due to lower water flows

\+ Mamquam, due to higher water flows

Waste heat down by approximately two-thirds in Q4 2016:

- Had declined less than 5% in first nine months of 2016
- Q4: New gas compressors on line in Toronto area due to geographical shifts in supply and demand; waste heat units near Company's plants being utilized less

Operations Update

Ontario

- Have completed putting Kapuskasing, Nipigon and North Bay in non-operational state
  - Plants now staffed with a minimum number of technicians
- Plan to return Tunis to service in 2018
  - Necessary work to be undertaken this year
  - Approximately $7 million cost (expense)

Optimization Update

- Invested a total of $25 million in 2013 through 2016
  - Most significant investments were at Nipigon, Morris and Curtis Palmer
  - Cash return of approximately $8 million in 2016
  - We believe it would have been higher under typical waste heat and water conditions
- Planned investment of approximately $1.5 million in 2017
  - Morris – third and final gas turbine upgrade
  - Other small projects
- Expect cash return of approximately $12 million in 2017
  - Assumes normal water flows at Curtis Palmer
- Future projects to be relatively modest
- Shifting focus to costs and PPA-related investments

Significant 2017 Outages

- Morris – gas turbine upgrade; Q2
- Frederickson – major outage for gas and steam turbines; Q2
- Orlando – major turbine maintenance; early spring
- Kenilworth –steam turbine overhaul; Q2

Cost Reduction Initiatives

- Eliminated layer of management between SVP Operations and plant managers
- Analyze and benchmark operation and maintenance costs
- Evaluate maintenance intervals, operational parameters, etc.
- Improve efficiency and operational performance; implement best practices

Commercial Update: Power Market Environment

- Most of our markets (U.S. and Canada) are impacted by an oversupply of generation
  - Low current and projected load growth
  - Public policy preference / subsidy for renewables
  - New gas-fired merchant construction driven by low natural gas prices and low cost capital
  - Lower spark spreads and low capacity values

- The Company's improved financial position enables us to withstand the current down cycle
  - Significant paydown of debt and reshaping of maturity profile
  - More than 50% reduction in overhead costs

- Current market conditions have modest impact on Company in near term
  - Most output is sold under PPAs with limited exposure to market price sensitivity
  - Exposure to market pricing is currently limited – Selkirk; Morris (in part); some market price sensitivity – Chambers, Kenilworth

- Market conditions impact plants with expiring PPAs
  - Next five years: PPAs expire for nine projects, 25% of MW, 30% of 2016 Project Adjusted EBITDA
  - Ability to renew expiring PPAs; economic terms of renewal

Commercial Update: Upcoming PPA Expirations

Ontario

- Oversupply of generation and low current market prices
- Kapuskasing and North Bay PPAs scheduled to expire December 2017
- Current market pricing does not support PPA extensions at this time
- Commercial team took innovative approach – announced January 9th agreements with OEFC and IESO
  - Receive fixed monthly payments through year end 2017 for Kapuskasing and North Bay
  - No delivery requirement; plants now in lay-up mode (cost savings)
  - Preserve option to restore plants to service, though unlikely in near term
  - Nipigon agreement similar (fixed monthly payments), though revised contract runs through October 2018, then reverts to PPA through December 2022
  - All parties benefit: Ratepayers – fuel cost savings; Province – reduced GHGs; Atlantic Power – improved cash flow, lower operating risk
- Continuing discussions with relevant parties on other potential initiatives

Commercial Update: Upcoming PPA Expirations (continued)

San Diego

- Three projects in San Diego area – PPAs with San Diego Gas & Electric, expiring in December 2019

- All located on Navy or Marine bases; sell steam to Navy under contracts expiring in February 2018
  - Contracts also provide right to use property
  - Steam sale is a requirement to maintain QF status
  - Loss of QF status or loss of site control could result in early termination of PPAs
  - Potential loss of EBITDA, and potential liabilities, in event of early termination

- Navy not intending to renew steam contracts
  - Issued solicitation for energy resiliency proposals at Naval Station and North Island (February 2017); Company will respond
  - If successful, would allow us use of the site(s); no guarantee that we will be successful

- Concurrently in negotiations with SDG&E for PPAs at two of three plants
  - Would be conditioned upon site control (dependent on agreement with Navy) and CPUC approval
  - Given market conditions, ~ 2/3 reduction in Project Adjusted EBITDA seems likely (compared to existing PPAs)

Commercial Update: Upcoming PPA Expirations (continued)

British Columbia / Williams Lake

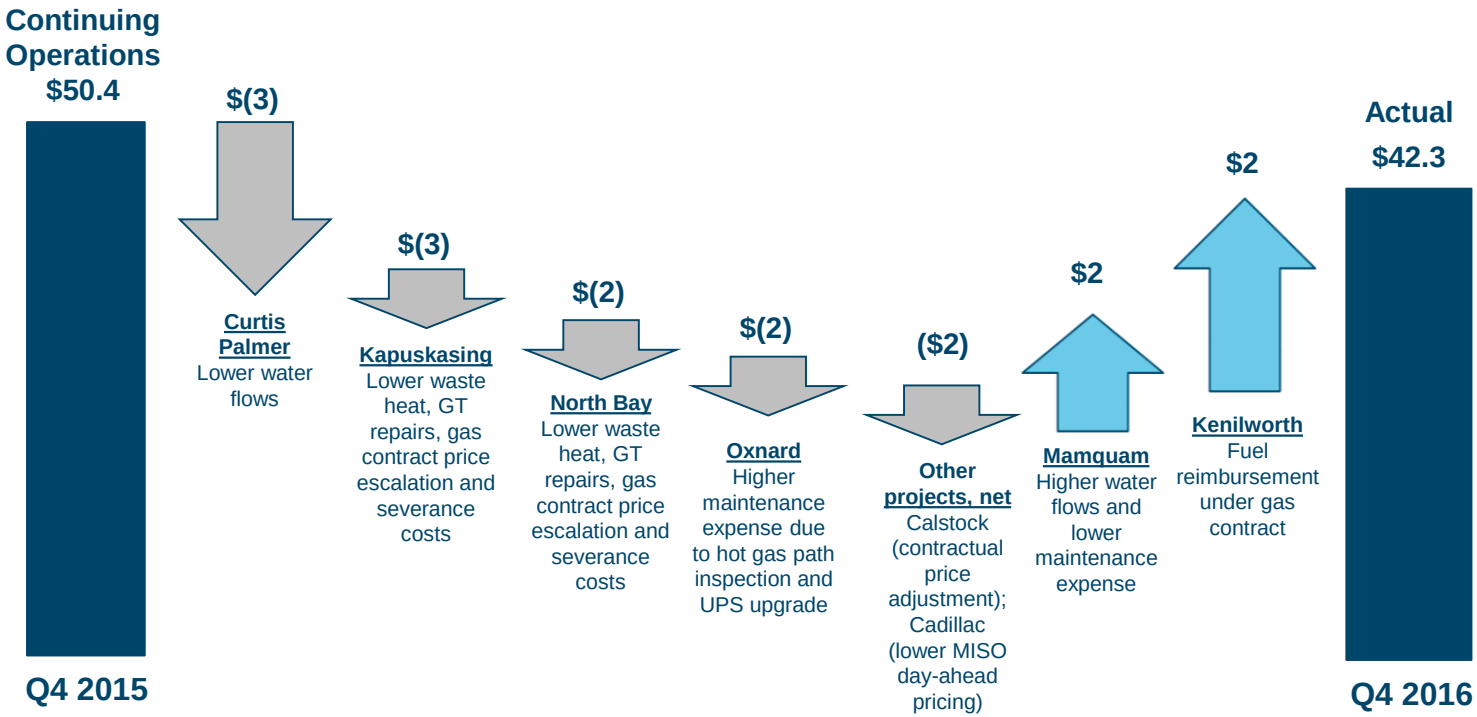
- Amended air permit for new fuel shredder on appeal
  - Environmental Appeal Board expected to issue schedule in near term
  - Appeal could take nine to twelve months
- Continuing discussions with BC Hydro on potential extension of existing PPA (expires March 2018)
  - Long-term extension unlikely in near term; BC Hydro Integrated Resource Plan under way (late 2018)
  - Short-term extension, if agreed to, would not require investment in new shredder
  - Support for the project across much of the province remains strong

Q4 2016: Accounting Issues

- Annual goodwill impairment test completed in Q4
  - Full impairment of remaining goodwill at Moresby Lake ($1.2 million)
  - No other impairments
  - Remaining goodwill at 12/31/16 was $36.0 million (Curtis Palmer, Morris, Nipigon)
- Termination of Power Purchase Agreements at Kapuskasing and North Bay
  - Replaced with Enhanced Dispatch Contracts through 12/31/17
  - Amortization of remaining intangibles associated with two PPAs ($12.7 million)
- Material weakness remediated as of December 31, 2016
  - Management developed and implemented new control procedures
  - Successfully tested these procedures in Q4 goodwill impairment analysis

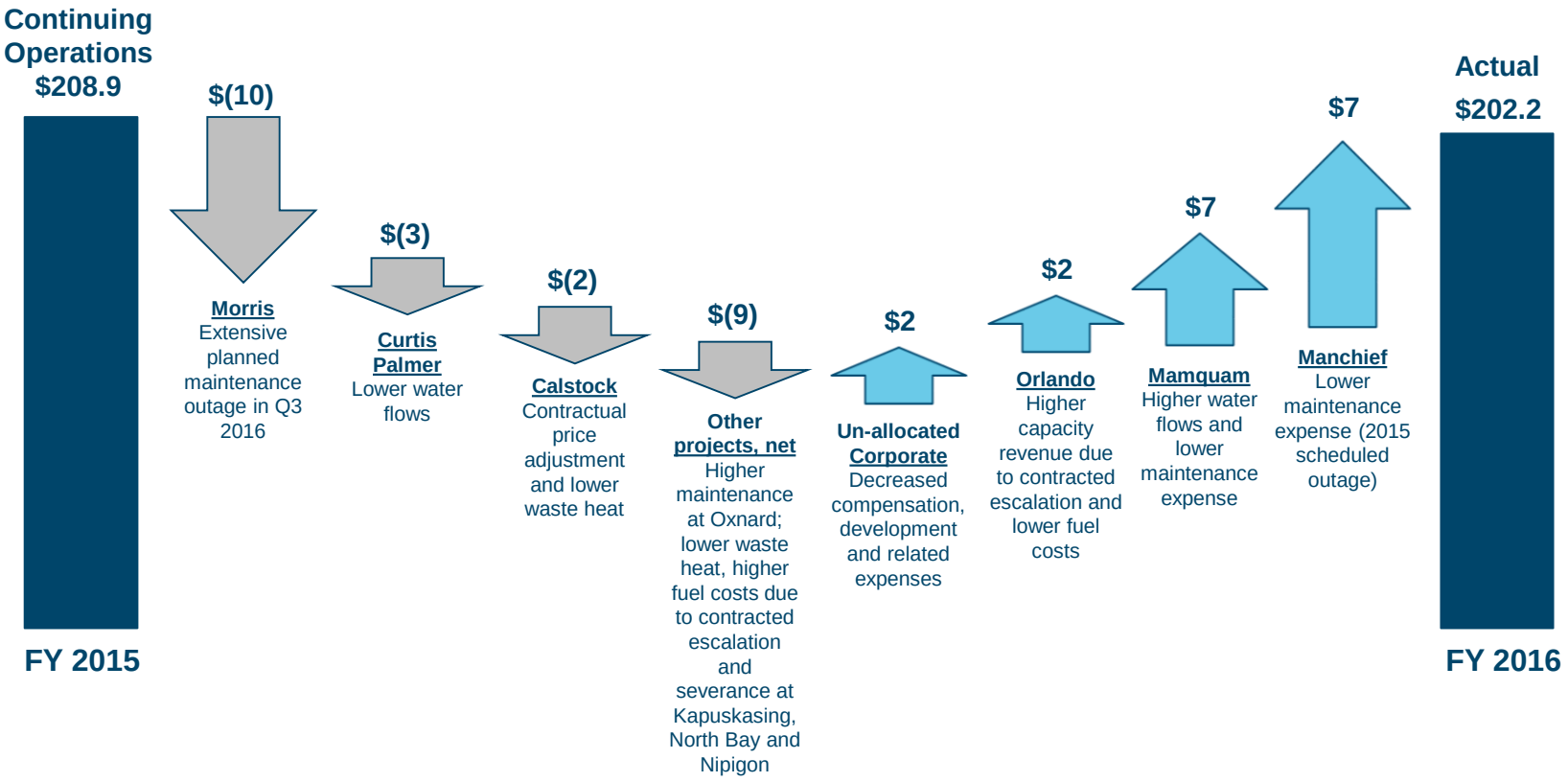
Project Adjusted EBITDA ($ millions)

Q4 2016: $42.3 vs. Q4 2015: $50.4



Project Adjusted EBITDA ($ millions)

FY 2016: $202.2 vs. FY 2015: $208.9



Cash Flow Results ($ millions)

(Unaudited)

Three months ended December 31,	2016	2015	Change
Cash provided by operating activities	$19.9	$19.7	$0.2
Severance and/or restructuring charges included above:	-	(0.1)	0.1
Significant uses of cash provided by operating activities:			
Term loan repayments[1]	(15.0)	(11.8)	(3.2)
Project debt amortization	(3.0)	(4.4)	1.4
Capital expenditures	(0.7)	(1.9)	1.2
Preferred dividends	(2.1)	(2.1)	-

Primary drivers:

- Lower Proj. Adj. EBITDA (8.1)
- Higher cash interest (2.9)
- Lower Corporate G&A +1.4
- Changes in other operating balances/write off DFC +9.8

Twelve months ended December 31,	2016	2015	Change
Cash provided by operating activities	$111.8	$87.4	$24.4
Severance and/or restructuring charges included above:	(0.2)	(3.9)	3.7
Significant uses of cash provided by operating activities:			
Term loan repayments[1]	(85.5)	(68.3)	(17.2)
Project debt amortization	(11.1)	(14.9)	3.8
Capital expenditures	(7.2)	(11.3)	4.1
Preferred dividends	(8.5)	(8.8)	0.3
Distribution to non-controlling interests	-	(3.8)	3.8

2015 attributable to Wind business

Primary drivers:

- Lower Proj. Adj. EBITDA (6.7)
- Lower cash interest +29.3
- Lower Corporate G&A +6.8
- Wind business (Disc. Ops.) (21.9)
- Changes in other operating balances/write off DFC +16.9

[1] Includes 1% mandatory annual amortization and targeted debt repayments.

Liquidity ($ millions)

Unaudited	9/30/16	12/31/16
Revolver capacity	$200.0	$200.0
Letters of credit outstanding	(88.7)	(81.5)
Unused borrowing capacity	111.3	118.5
Unrestricted cash	93.8	85.6
Total Liquidity	**$205.1**	**$204.1**

Note: Liquidity does not include restricted cash of $12.6 million at September 30, 2016 and $13.3 million at December 31, 2016.

(7.2)

$7 reduction in LCs (mark-to-market on gas contract)

Includes ~ $60 at APC (parent); balance is at the plants or other subsidiaries
(10) Need for working capital purposes
~ 50 Discretionary cash available

Progress on Debt Reduction and Leverage ($ millions)

(Unaudited)

		Leverage [1]
12/31/2013 consolidated debt	**$1,876**	*9.5x*
12/31/2014 consolidated debt	**1,755**	*6.9x*
12/31/2015 consolidated debt	**1,019**	*5.7x*
3/31/2016 consolidated debt	**994**	*5.6x*
Term loan refinancing:		
Issuance of new term loan (April)	700	
Repayment of previous term loan (April)	(448)	
3/31/16 consolidated debt – pro forma	**1,246**	*7.1x*
Changes Q2-Q4 2016:		
Redemption of 2017 convertible debentures (May)	(110)	
Repurchase of 2019 convertible debentures (July)	(63)	
Amortization of new term loan (Q2 – Q4)	(60)	
Amortization of project debt (Q2 – Q4)	(9)	
Incremental F/X impact (unrealized gain) (Q2 – Q4)	(7)	
12/31/16 consolidated debt	**997**	*5.6x*

Net increase in debt $252

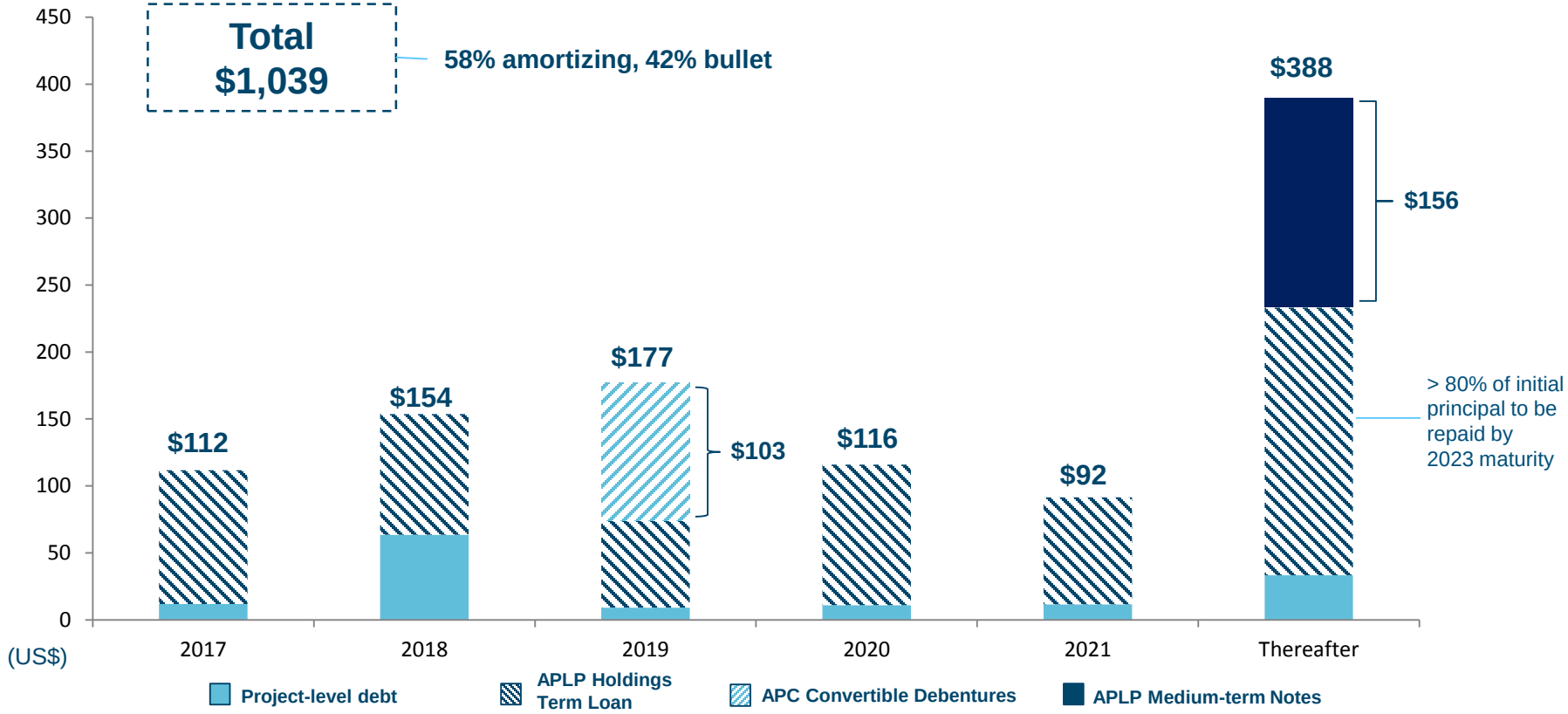
By year end 2016, had paid down all but $10 of $252 increase

Total net reduction in consolidated debt of approximately $880 million since YE 2013; in addition, debt at equity-owned projects has been reduced by $92 million.

[1] Consolidated gross debt to trailing 12-month Adjusted EBITDA (after Corporate G&A)

Debt Repayment Schedule at December 31, 2016 ($ millions)

Includes Company's share of debt at equity-owned projects

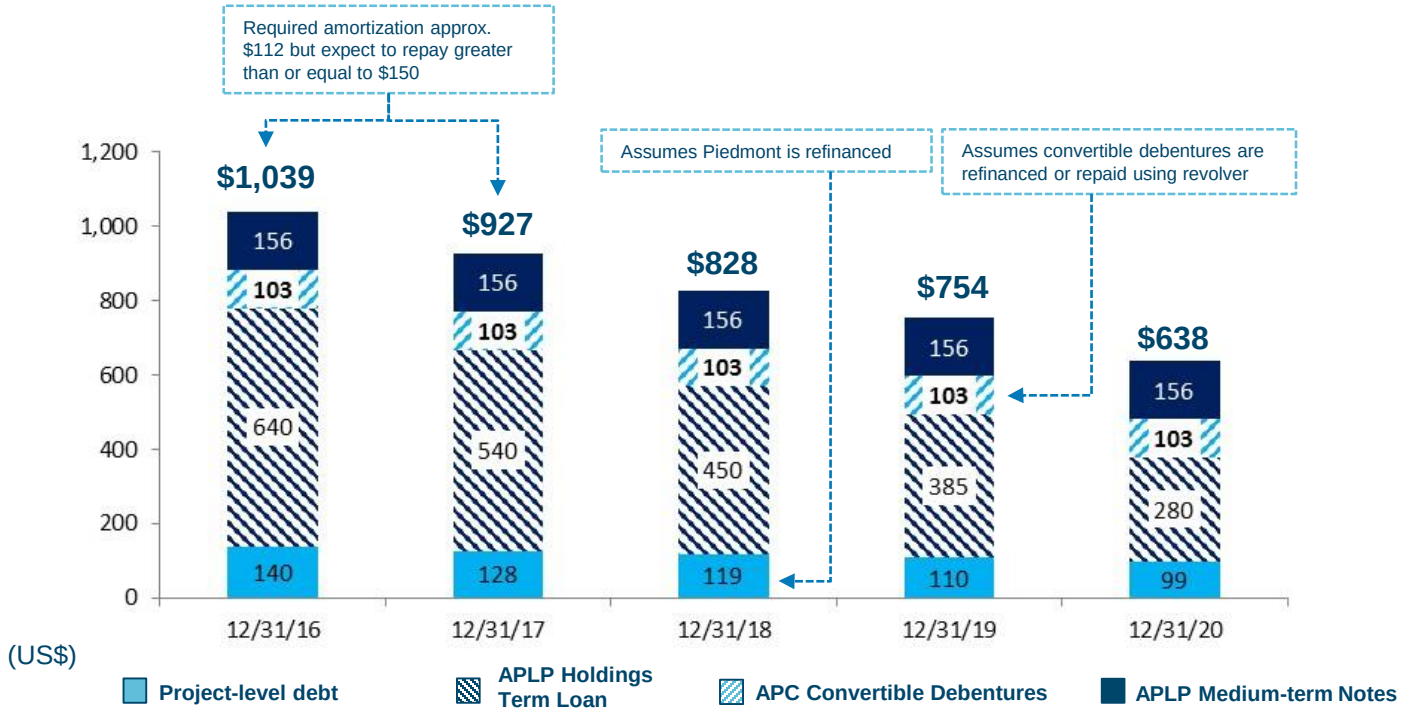


- Project-level non-recourse debt totaling $140, including $43 at Chambers (equity method); includes Piedmont bullet maturity of $54.1 (2018); remainder amortizes over the life of the project PPAs
- $640 amortizing term loan (maturing in April 2023), which has 1% annual amortization and mandatory prepayment via the greater of a 50% sweep or such other amount that is required to achieve a specified targeted debt balance (combined annual average of ~ $82)
- $103 (US$ equivalent) of convertible debentures (maturing in June and December 2019)
- $156 APLP Medium-term Notes due in 2036

Note: C$ denominated debt was converted to US$ using US$ to C$ exchange rate of $1.3427.

Projected Debt Balances ($ millions)

Includes Company's share of debt at equity-owned projects



Year-end 2016 – Year-end 2020:

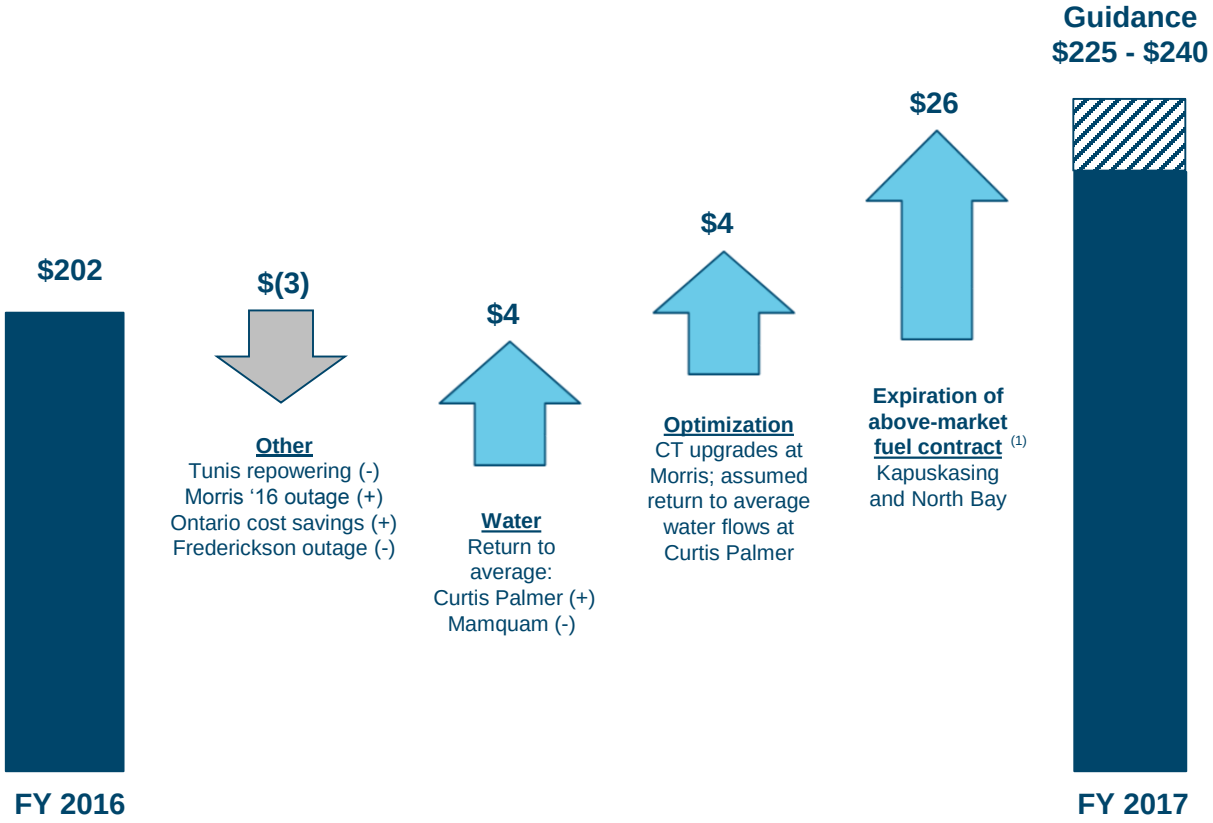
- Term loan – Repay $360, ending balance $280 – annual interest cost savings $22 by 2021
- Project debt (proportional) – Repay $41, ending balance $99 – annual interest cost savings $2
- Assumes Piedmont ($54) is refinanced at maturity in 2018
- Assumes 2019 convertible debentures ($103) are refinanced or repaid using revolver (no change in debt)
  - If redeemed or repurchased using cash, annual interest savings of up to $6 in 2020

Cumulative Paydown of Debt Drives Interest Cost Savings

Note: C$ denominated debt was converted to US$ using US$ to C$ exchange rate of $1.3427.

2017 Project Adjusted EBITDA Guidance – by Key Drivers ($ millions)

2016 Actual $202; 2017 Guidance $225 to $240



Incremental margin driven by expiration of above-market fuel contracts at Kapuskasing & North Bay, higher Optimization returns and assumed average water flows at Curtis Palmer (+) and Mamquam (-)

The Company has not provided guidance for Project income or Net income because of the difficulty of making accurate forecasts and projections without unreasonable efforts with respect to certain highly variable components of these comparable GAAP metrics, including changes in the fair value of derivative instruments and foreign exchange gains or losses. These factors, which generally do not affect cash flow, are not included in Project Adjusted EBITDA.

(1) The gas supply contract for Kapuskasing and North Bay was significantly above market. This expired on December 31, 2016 independent of the contract announcements of January 9, 2017. The positive variance shown represents the difference between incurred fuel costs in 2016 and the fuel credit provided to the customer under the 2017 Enhanced Dispatch Agreements for both plants. Note, had the PPAs remained in effect and the plants continued to operate, the variance would have been the same as the Company would have been purchasing gas at a market price, resulting in savings versus the above-market cost incurred in 2016.

Bridge of 2017 Project Adjusted EBITDA Guidance to Cash Provided by Operating Activities ($ millions)

2017 Project Adjusted EBITDA Guidance[1]	**$225 - $240**
Adjustment for equity method projects[2]	(1)
Corporate G&A expense	(22)
Cash interest payments	(67)
Cash taxes	(4)
Other	-
Cash provided by operating activities	**$130 - $145**

2016 Actual= $22.6

2016 Actual= $70.7

Note: For purposes of providing a reconciliation of Project Adjusted EBITDA guidance, impact on Cash provided by operating activities of changes in working capital is assumed to be nil.

2017 expected uses of cash provided by operating activities:		**2016 Actual**
Term loan repayments[3]	$100	$85.5
Project debt amortization	12	11.1
Capital expenditures	5	7.5
Preferred dividend payments	9	8.5

[1] Initially provided March 2, 2017.
[2] Represents difference between Project Adjusted EBITDA and cash distribution from equity method projects.
[3] Includes 1% mandatory annual amortization and targeted debt repayments.

How We Think About the Business

- Think and act like owners for the long haul
  - Focus is on free cash flow and intrinsic value creation
  - Believe share price will reflect that over time
- Power generation business – capital-intensive, cyclical, commodity-priced, government policy driven
  - Experience shows you make money by being countercyclical
  - U.S. IPP shares near historic lows, but contracted assets going for high multiples
    - We have been buying in the former market, selling in the latter
    - Since December 2015, we repurchased nearly $20 million of common shares at a discount to our estimate of intrinsic value
    - Limiting factor on share repurchases – commitment to delevering ($150 million or more in 2017)
    - Management and directors have purchased 1.4 million shares since Q2 2015 (CEO joined Jan. 2015)
  - Sold wind assets in 2015 for $350 million at attractive multiple; also considering the sale of Piedmont
- Intrinsic value
  - Not a point estimate, but a wide range of outcomes depending on assumptions
  - Highly sensitive to discount rate assumptions and forward power curves
  - Hydro plants have strong cash flow potential post-PPA and significant terminal value

Different Scenarios and How They Affect the Value of Atlantic Power

Lower for Longer - the “tough slog” case

- Take steps to protect the downside
  - Debt reduction and interest cost savings
  - Reshape maturity profile
  - Overhead cost reductions
  - Next area of focus: plant operation and maintenance (O&M)
- Take a disciplined and creative approach to PPA renewals, such as we did at Morris and in Ontario
- Even assuming no PPA renewals next five years:
  - Possible to mitigate half the impact of lower EBITDA on cash flow through cost reductions (mostly from debt repayment)
  - Can still delever during this period
- Withstand extended downturn
- Strong cash flows from hydro assets well into the future – significant long-term value

Base Case

- Power curves are higher than current, but not at levels of even a year ago
- Does not assume that all gas and biomass plants are recontracted post-PPA
- Assumes significant reduction from certain plants that are recontracted
- Strong cash flows from hydro assets well into the future – significant long-term value

Reflation

- Recovery in forward curves
- Increases estimates of future cash flows (post-PPA) and terminal value of hydros

Growth

Beginning to Implement an External Growth Strategy

- Reticent on external growth past two years
  - Focused on mitigating downside risks
  - Internal / organic uses of capital had higher returns
  - Financial / human resources focused on restructuring
  - Patient; didn't see compelling opportunities

- Shifting focus toward industrial markets and customers
  - Wholesale rates have declined significantly while retail and industrial rates have not declined in line with wholesale rates
  - Have strong existing industrial customer relationships at several of our plants
  - Beginning to seek new opportunities with other industrial customers
  - Well within our core competencies
  - Right size investment for us; too small for many others

- Successful development of new power plants at industrial sites is a multi-year process
  - Will provide updates on our progress

Appendix

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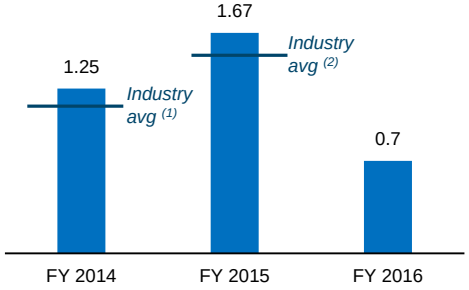
FY December 2016 Operational Performance:

Lower availability and generation due to planned maintenance outages and lower generation at Frederickson and Manchief

Safety: Total Recordable Incident Rate



(1) 2014 BLS data, generation companies = 1.1
(2) 2015 BLS data, generation companies = 1.4

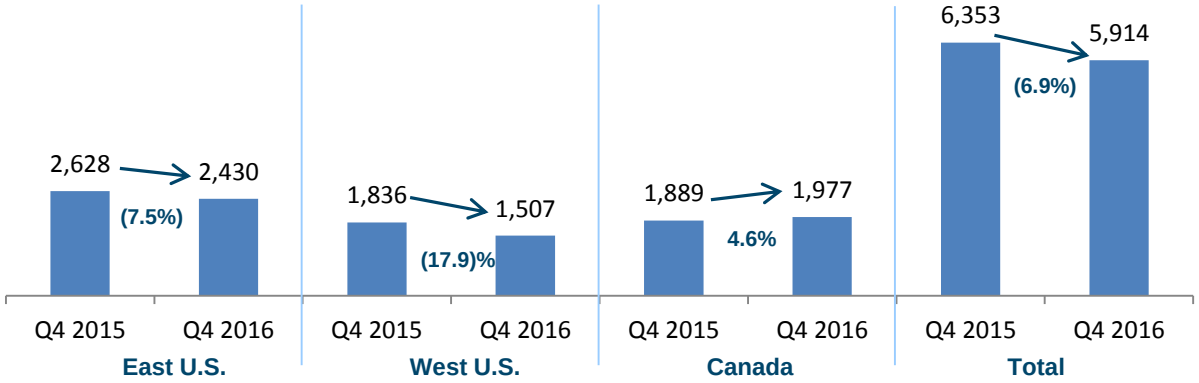
Availability (weighted average)

	FY 2016	FY 2015
East U.S.	93.1%	96.9%
West U.S.	92.1%	92.8%
Canada	95.3%	93.9%
Total	**93.3%**	**95.2%**

Availability factor down:

- − Morris (extensive planned maintenance outage in Q3 2016)
- + Mamquam (maintenance outage in September and October 2015)
- + Manchief (maintenance outage in 2015)

Aggregate Power Generation FY December 2016 vs. FY December 2015 (thousands, Net MWh)



Generation down 6.9% year-on-year:

- – Frederickson, lower dispatch due to mild weather and higher availability of hydro plants in the region
- – Manchief, lower dispatch
- – Morris, extended turnaround outage for host
- – Selkirk, lower dispatch due to low merchant power prices
- + Mamquam, higher water flows and underwent maintenance outage in 2015

Waste heat down approximately 20%

Capitalization ($ millions)

	December 31, 2015		December 31, 2016	
Long-term debt, incl. current portion [1]				
APLP Medium-Term Notes [2]	$152		$156	
Revolving credit facility	-		-	
Term Loan	473		640	
Project-level debt (non-recourse)	108		97	
Convertible debentures [3]	285		103	
Total long-term debt, incl. current portion	**$1,018**	**70%**	**$996**	**78%**
Preferred shares	221	15%	221	17%
Common equity [4]	214	15%	65	5%
Total shareholders equity	**435**	**30%**	**286**	**22%**
Total capitalization	**$1,453**	**100%**	**$1,282**	**100%**

(1) Debt balances are shown before unamortized discount and unamortized deferred financing costs
(2) Period-over-period change due to F/X impacts
(3) Period-over-period change due to F/X impacts, repurchases of convertible debentures under the NCIB of $18.8 million, redemption of $110.1 million of 2017 convertible debenture and repurchase of $62.7 million of 2019 convertible debentures.
(4) Common equity includes other comprehensive income and retained deficit

Note: Table is presented on a consolidated basis and excludes equity method projects

Capital Summary at December 31, 2016 ($ millions)

Atlantic Power Corporation

		Actual	
	Maturity	Amount	Interest Rate
Convertible Debentures (ATP.DB.U)	6/2019	$42.6	5.75%
Convertible Debentures (ATP.DB.D)	12/2019	$60.3 (C$81.0)	6.0%

APLP Holdings Limited Partnership

	Actual		
	Maturity	Amount	Interest Rate
Revolving Credit Facility	4/2021	$0	LIBOR + 5.00%
Term Loan	4/2023	$639.9	6.00-6.20%[1]

Atlantic Power Limited Partnership

	Actual		
	Maturity	Amount	Interest Rate
Medium-term Notes	6/2036	$156.4 (C$210)	5.95%
Preferred shares (AZP.PR.A)	N/A	$93.1 (C$125)	4.85%
Preferred shares (AZP.PR.B)	N/A	$45.5 (C$58.5)	5.57%
Preferred shares (AZP.PR.C)	N/A	$31.0 (C$41.5)	4.68%[2]

Atlantic Power Transmission & Atlantic Power Generation

	Maturity	Amount	Interest
Project-level Debt (consolidated)	Various	$97.1	4.00%-8.22%
Project-level Debt (equity method)	Various	$42.9	4.50%-5.00%

[1]Includes impact of interest rate swaps; [2] Set on December 1, 2016 for March 31, 2016 dividend payment. Will be reset quarterly based on sum of the Canadian Government 90-day Treasury Bill yield (using the three-month average result plus 4.18%). Note: C$ denominated debt was converted to US$ using US$ to C$ exchange rate of $1.3427.

APLP Holdings Term Loan Cash Sweep Calculation

APLP Holdings Adjusted EBITDA
(note: excludes Piedmont; is after majority of Atlantic Power G&A expense)

Less:
Capital expenditures
Cash taxes

= Cash flow available for debt service

Less:
APLP Holdings consolidated cash interest
(revolver, term loan, MTNs, EPP, Cadillac)

= Cash flow available for cash sweep

Calculate 50% of cash flow available for sweep
Compare 50% cash flow sweep to amount required to achieve targeted debt balance

Must repay greater of 50% or the amount required to achieve targeted debt balance for that quarter

If targeted debt balance is > 50% of cash flow sweep:
- Repay amount required to achieve target, up to 100% of cash flow available from sweep
- Remaining amount, if any, to Company

If targeted debt balance is < 50% of cash flow sweep:
- Repay 50% minimum
- Remaining 50% to Company

Expect cash sweep to average 65% to 70% over the life of the loan, though higher in early years, and with considerable variability from year to year

Expect > 80% of principal to be repaid by maturity through mandatory and targeted repayments

Notes:
The cash sweep calculation occurs at each quarter-end. Targeted debt balances are specified in the credit agreement for each quarter through maturity.

APLP Holdings Credit Facilities – Financial Covenants

Fiscal Quarter	Leverage Ratio	Interest Coverage Ratio
3/31/2017	6.00:1.00	2.75:1.00
6/30/2017	5.50:1.00	3.00:1.00
9/30/2017	5.50:1.00	3.00:1.00
12/31/2017	5.50:1.00	3.00:1.00
3/31/2018	5.50:1.00	3.00:1.00
6/30/2018	5.00:1.00	3.00:1.00
9/30/2018	5.00:1.00	3.00:1.00
12/31/2018	5.00:1.00	3.00:1.00
3/31/2019	5.00:1.00	3.00:1.00
6/30/2019	5.00:1.00	3.25:1.00
9/30/2019	5.00:1.00	3.25:1.00
12/31/2019	5.00:1.00	3.25:1.00
3/31/2020	5.00:1.00	3.25:1.00
6/30/2020	4.25:1.00	3.5:1.00
9/30/2020	4.25:1.00	3.5:1.00
12/31/2020	4.25:1.00	3.5:1.00
3/31/2021	4.25:1.00	3.5:1.00
6/30/2021	4.25:1.00	3.75:1.00
9/30/2021	4.25:1.00	3.75:1.00
12/31/2021	4.25:1.00	3.75:1.00
3/31/2022	4.25:1.00	3.75:1.00
6/30/2022	4.25:1.00	4.00:1.00
9/30/2022	4.25:1.00	4.00:1.00
12/31/2022	4.25:1.00	4.00:1.00
3/31/2023	4.25:1.00	4.00:1.00

Leverage ratio:

Consolidated debt to Adjusted EBITDA, calculated for the trailing four quarters.

Consolidated debt includes both long-term debt and the current portion of long-term debt at APLP Holdings, specifically the amount outstanding under the term loan and the amount borrowed under the revolver, if any, the Medium Term Notes, and consolidated project debt (Epsilon Power Partners and Cadillac).

Adjusted EBITDA is calculated as the Consolidated Net Income of APLP Holdings plus the sum of consolidated interest expense, tax expense, depreciation and amortization expense, and other non-cash charges, minus non-cash gains. The Consolidated Net Income includes an allocation of the majority of Atlantic Power G&A expense. It also excludes earnings attributable to equity-owned projects but includes cash distributions received from those projects.

Interest Coverage ratio:

Adjusted EBITDA to consolidated cash interest payments, calculated for the trailing four quarters.

Adjusted EBITDA is defined above.

Consolidated cash interest payments include interest payments on the debt included in the Consolidated debt ratio defined above.

Note, the project debt, Project Adjusted EBITDA and cash interest expense for Piedmont are not included in the calculation of these ratios because the project is not included in the collateral package for the credit facilities.

Power Projects

Atlantic Power Corporation

APLP Holdings Limited Partnership

Atlantic Power Limited Partnership

Project	Location	Type	Economic Interest	Net MW	Contract Expiry
Calstock	Ontario	Biomass	100%	35	6/2020
Kapuskasing	Ontario	Nat. Gas	100%	40	12/2017
Mamquam	B.C.	Hydro	100%	50	9/2027
Morseby Lake	B.C.	Hydro	100%	6	8/2022
Nipigon	Ontario	Nat. Gas	100%	40	12/2022
North Bay	Ontario	Nat. Gas	100%	40	12/2017
Tunis	Ontario	Nat. Gas	100%	40	11/2032 [2]
Williams Lake	B.C.	Biomass	100%	66	3/2018
Curtis Palmer	New York	Hydro	100%	60	12/2027
Kenilworth	New Jersey	Nat. Gas	100%	29	9/2018
Morris	Illinois	Nat. Gas	100%	177	12/2034
Frederickson	Washington	Nat. Gas	50.15%	125	8/2022
Manchief	Colorado	Nat. Gas	100%	300	4/2022
Naval Station	California	Nat. Gas	100%	47	12/2019[3]
Naval Training	California	Nat. Gas	100%	25	12/2019[3]
North Island	California	Nat. Gas	100%	40	12/2019[3]
Oxnard	California	Nat. Gas	100%	49	5/2020

Atlantic Power Transmission & Atlantic Power Generation

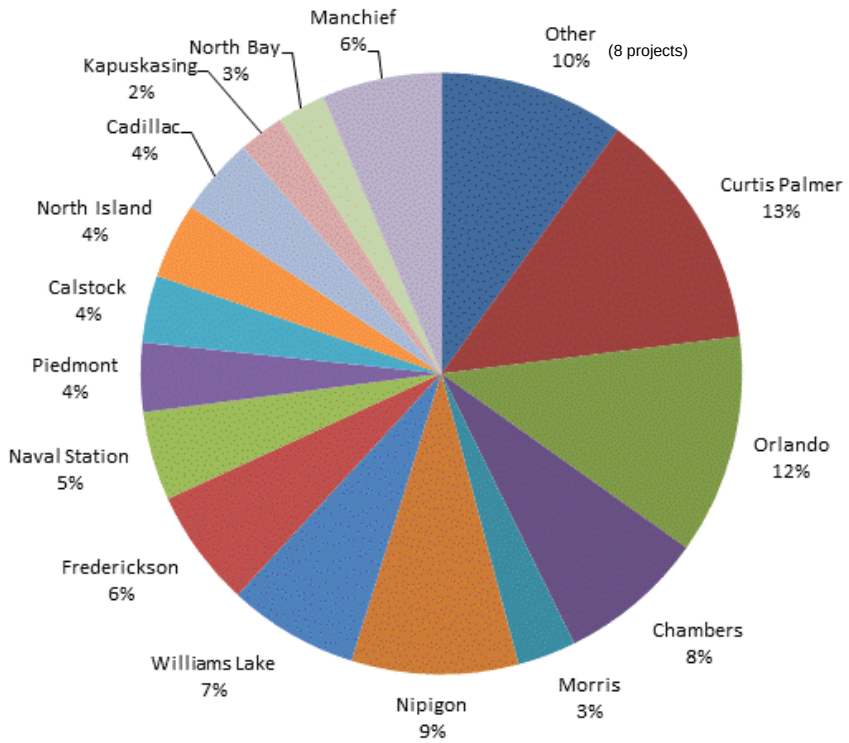
Project	Location	Type	Economic Interest	Net MW	Contract Expiry
Cadillac	Michigan	Biomass	100%	40	12/2028
Chambers	New Jersey	Coal	40%	105	12/2024
Orlando	Florida	Nat. Gas	50%	65	12/2023
Piedmont [1]	Georgia	Biomass	100%	55	12/2032
Selkirk	New York	Nat. Gas	17.7%	61	Merchant
Koma Kulshan	Washington	Hydro	49.8%	6	12/2037

- Canada
- East U.S.
- West U.S.

[1] Excluded from the APLP Holdings collateral package
[2] 15-year contract commences between Nov. 2017 and Jun. 2019
[3] May terminate earlier if land use agreements with U.S. Navy expiring in Feb. 2018 are not extended

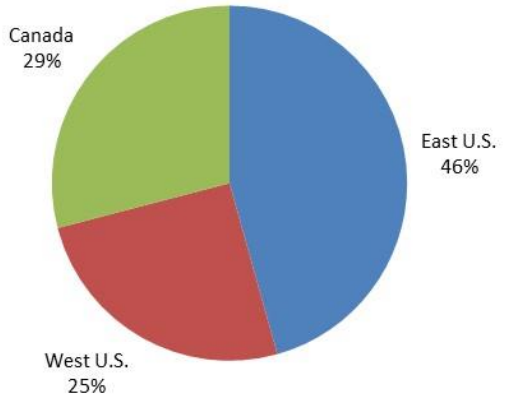
Earnings and Cash Flow Diversification by Project

No single project contributed more than 13% to Project Adjusted EBITDA for the twelve months ended December 31, 2016 [1]

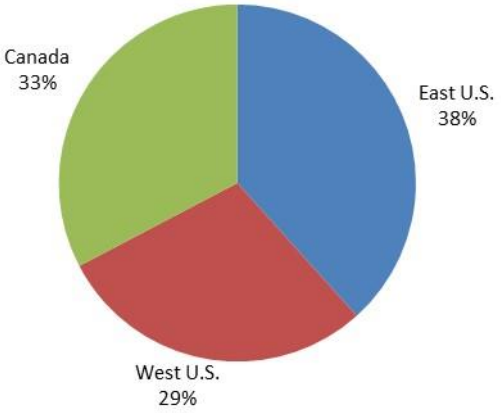


Capacity (MW) by Segment
East U.S.: 44%
West U.S.: 44%
Canada: 12%

Twelve months ended December 31, 2016 Project Adjusted EBITDA by Segment [1]



Twelve months ended December 31, 2016 Cash Distributions from Projects by Segment [2]

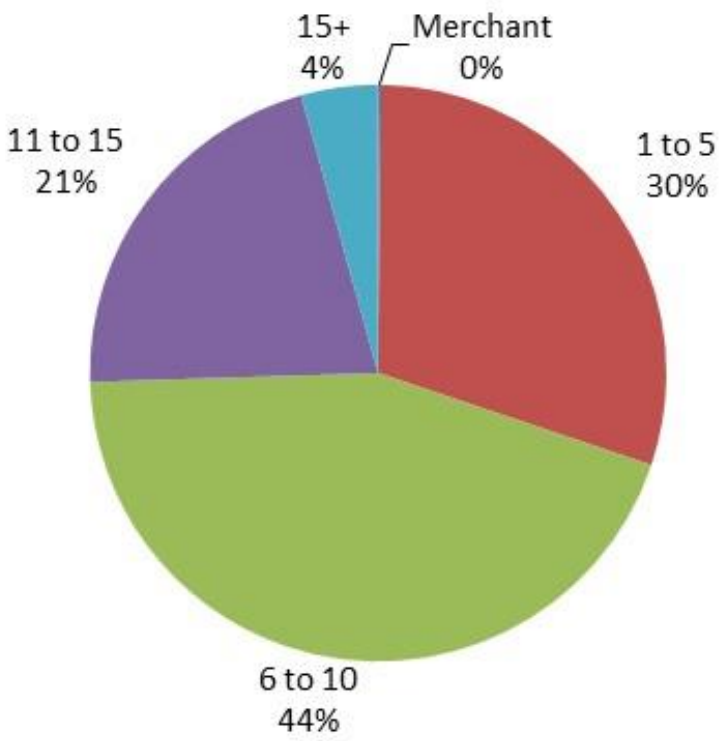


[1] Based on $202.2 million in Project Adjusted EBITDA for the twelve months ended December 31, 2016. Un-allocated corporate segment is included in "Other" category for project percentage allocation and allocated equally among segments for the twelve months ended December 31, 2016 Project Adjusted EBITDA by Segment.
[2] Based on $185.7 million in Cash Distributions from Projects for the twelve months ended December 31, 2016.

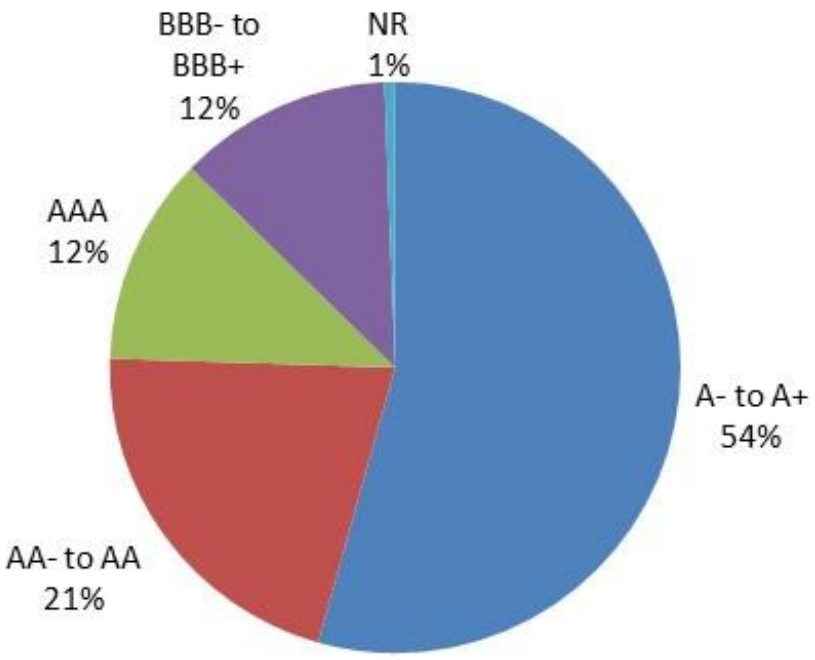
Majority of Cash Flows Covered by Contracts with More Than Five Years Remaining

Contracted projects have an average remaining PPA life of 6.4 years [1]

PPA Length (years) [1]



Pro Forma Offtaker Credit Rating [1]



70% of 2016 Project Adjusted EBITDA generated from PPAs that expire beyond the next five years

[1] Weighted by FY 2016 Project Adjusted EBITDA

Results Summary, Q4 / FY 2016 vs Q4 / FY 2015 ($ millions)

unaudited

Summary of Financial and Operating Results

	Three months ended December 31		Twelve months ended December 31	
	2016	2015	2016	2015
Financial Results				
Project revenue	$93.4	$98.4	$399.2	$420.2
Project income (loss)	13.3	(104.3)	10.1	(41.4)
Net (loss) income attributable to Atlantic Power Corp.	(6.6)	(88.6)	(122.4)	(62.4)
Cash provided by operating activities	19.9	19.7	111.8	87.4
Project Adjusted EBITDA	42.3	50.4	202.2	208.9
Operating Results				
Aggregate power generation (thousands of Net MWh)	1,364.2	1,646.4	5,914.0	6,353.3
Weighted average availability	93.0%	96.0%	93.3%	95.2%

Segment Results

	Three months ended December 31		Twelve months ended December 31	
	2016	2015	2016	2015
Project income (loss)				
East U.S.	$14.3	($1.3)	$31.2	$38.7
West U.S.	(2.0)	0.3	11.8	7.6
Canada	(2.6)	(103.6)	(35.7)	(85.7)
Un-allocated Corporate	3.7	0.2	2.8	(2.0)
Total	**13.3**	**(104.3)**	**10.1**	**(41.4)**
Project Adjusted EBITDA				
East U.S.	$21.9	$23.6	$92.4	$104.8
West U.S.	7.7	9.9	51.2	46.9
Canada	12.6	16.8	58.8	59.7
Un-allocated Corporate	0.1	0.1	(0.2)	(2.5)
Total	**42.3**	**50.4**	**202.2**	**208.9**

G&A and Development Expenses ($ millions)

	2013 Actual	2014 Actual	2015 Actual	2016 Actual
Development [1]	$7.2	$3.7	$1.1	n/a [1]
Project G&A and other	11.4	3.8	1.5	$0.2
Corporate G&A[2]	35.2	37.9	29.4	22.6
Total overhead	**$53.8**	**$45.4**	**$31.9**	**$22.8**

Included in Project Adj. EBITDA

"Administration" expense on Income Statement; not included in Project Adj. EBITDA

Project G&A and other:
- Operations & Asset Management
- Environmental, Health & Safety
- Ridgeline
- Project Accounting

Corporate G&A:
- Executive & Financial Management
- Treasury, Tax, Legal, HR, IT, Commercial activities
- Corporate Accounting
- Office & administrative costs
- Public company costs
- One-time costs (mostly severance)

2016 actual level represents a 58% reduction from 2013

(1) Includes approximately $3 million annual contractual obligation related to Ridgeline acquisition that terminated in the first quarter of 2015. For 2016 and beyond, all Development spend will be recorded in Corporate G&A.
(2) Includes $6 severance in 2014; approximately $4 severance and $2 restructuring in 2015

Net Operating Loss Carryforwards (NOLs) ($ millions)

As of December 31, 2016, we had NOLs scheduled to expire per the schedule below that we can utilize to offset future taxable income:

2027	$43.2
2028	93.0
2029	70.8
2030	25.8
2031	13.4
2032	19.0
2033	137.7
2034	167.0
2035	17.0
2036	32.1
Total	**$619.0**

- NOLs represent approximately $216 million in potential future tax savings
- Although we expect these NOLs will be available to us as a future benefit:
  - Some of the NOLs are subject to limitations on their use.
  - Concurrent with closing the term loan refinancing, we implemented a tax restructure by moving APG and APT underneath USGP to form one consolidated tax group. We believe this structure will allow the Company to operate in the most tax-efficient manner going forward.

Note: USGP = Atlantic Power (US) GP Holdings Inc.; APG = Atlantic Power Generation; APT = Atlantic Power Transmission

Project Income by Project ($ millions)

Unaudited

		Three months ended December 31		Twelve months ended December 31	
		2016	2015	2016	2015
East U.S.	**Accounting**				
Cadillac	Consolidated	$0.4	$1.2	$2.9	$3.0
Curtis Palmer	Consolidated	1.9	(8.6)	(4.4)	0.6
Morris	Consolidated	0.6	2.2	(0.1)	12.6
Piedmont	Consolidated	0.4	(2.4)	(5.0)	(6.7)
Kenilworth	Consolidated	1.9	0.2	1.2	0.7
Chambers	Equity method	0.3	0.5	4.9	5.7
Orlando	Equity method	9.1	5.7	32.1	22.6
Selkirk	Equity method	(0.3)	(0.1)	(0.4)	0.2
Total		14.3	(1.3)	31.2	38.7
West U.S.					
Manchief	Consolidated	0.3	0.7	1.9	(5.2)
Naval Station	Consolidated	-	(0.2)	3.5	3.9
North Island	Consolidated	0.4	0.4	4.0	4.1
Naval Training Center	Consolidated	(0.1)	(0.1)	1.7	1.8
Oxnard	Consolidated	(3.6)	(1.5)	(2.2)	-
Frederickson	Equity method	0.8	0.8	2.2	2.6
Koma Kulshan	Equity method	0.2	0.2	0.7	0.4
Total		(2.0)	0.3	11.8	7.6
Canada					
Calstock	Consolidated	0.5	(2.5)	5.2	2.8
Kapuskasing	Consolidated	(4.2)	3.8	(4.8)	9.0
Mamquam	Consolidated	1.7	(0.4)	(42.4)	1.1
Nipigon	Consolidated	4.6	3.6	9.1	7.2
North Bay	Consolidated	(3.4)	3.8	(5.8)	8.5
Williams Lake	Consolidated	0.1	(111.9)	5.7	(113.5)
Other [1]	Consolidated	(1.9)	-	(2.7)	(0.8)
Total		(2.6)	(103.6)	(35.7)	(85.7)
Totals					
Consolidated projects		(0.4)	(111.7)	(32.2)	(70.9)
Equity method projects		10.1	7.1	39.5	31.5
Un-allocated corporate		3.6	0.3	2.8	(2.0)
Total Project Income		$13.3	($104.3)	$10.1	($41.4)

Project Adjusted EBITDA by Project ($ millions)

Unaudited

		Three months ended December 31		Twelve months ended December 31	
		2016	2015	2016	2015
East U.S.	**Accounting**				
Cadillac	Consolidated	$1.9	$2.6	$8.5	$8.8
Curtis Palmer	Consolidated	5.8	8.9	26.5	29.8
Morris	Consolidated	2.5	3.2	6.4	16.5
Piedmont	Consolidated	0.2	(0.1)	7.5	7.6
Kenilworth	Consolidated	2.7	0.8	3.8	3.2
Chambers	Equity method	3.0	3.3	16.0	17.0
Orlando	Equity method	6.1	5.3	24.0	22.0
Selkirk	Equity method	(0.2)	(0.3)	(0.3)	0.1
Total		21.9	23.6	92.4	104.8
West U.S.					
Manchief	Consolidated	3.1	3.4	13.0	5.8
Naval Station	Consolidated	1.4	1.3	9.7	10.2
North Island	Consolidated	1.5	1.4	8.3	8.4
Naval Training Center	Consolidated	0.7	0.7	4.8	4.9
Oxnard	Consolidated	(2.6)	(0.4)	2.0	4.3
Frederickson	Equity method	3.3	3.3	12.1	12.5
Koma Kulshan	Equity method	0.4	0.3	1.1	0.8
Total		7.7	9.9	51.2	46.9
Canada					
Calstock	Consolidated	1.2	2.4	7.3	9.5
Kapuskasing	Consolidated	0.8	3.7	5.0	7.8
Mamquam	Consolidated	2.2	0.1	9.4	2.7
Nipigon	Consolidated	5.0	5.2	18.2	18.3
North Bay	Consolidated	1.5	3.7	5.2	7.2
Williams Lake	Consolidated	2.3	1.5	14.2	14.0
Other [1]	Consolidated	(0.5)	0.3	(0.6)	0.2
Total		12.6	16.8	58.8	59.7
Totals					
Consolidated projects		29.7	38.4	149.5	159.1
Equity method projects		12.6	11.9	52.9	52.3
Un-allocated corporate		0.1	0.1	(0.2)	(2.5)
Total Project Adjusted EBITDA		$42.3	$50.4	$202.2	$208.9

	Three months ended December 31		Twelve months ended December 31	
	2016	2015	2016	2015
Total Project Adjusted EBITDA	$42.3	$50.4	$202.2	$208.9
Other project expense	$0.2	$0.3	($0.3)	($2.0)
Impairment	1.2	127.9	85.9	127.8
Interest expense, net	2.7	2.1	10.9	9.8
Depreciation and amortization	42.7	31.3	133.5	130.1
Change in fair value of derivative instruments	(17.8)	(6.8)	(37.9)	(15.4)
Project income (loss)	$13.3	($104.3)	$10.1	($41.4)
Other income, net	-	-	(3.9)	(3.1)
Foreign exchange loss (gain)	(5.0)	(11.2)	13.9	(60.3)
Interest expense, net	18.2	15.8	106.0	107.1
Administration	5.0	6.4	22.6	29.4
(Loss) from continuing operations before income taxes	(4.8)	(115.3)	(128.5)	(114.5)
Income tax (benefit) expense	(0.4)	(29.9)	(14.6)	(30.4)
Net (loss) income from continuing operations	(4.4)	(85.4)	(113.9)	(84.1)
Net income from discontinued operations, net of tax	-	1.1	-	(19.5)
Net (loss) income	(4.4)	(86.5)	(113.9)	(64.6)
Net (loss) attributable to noncontrolling interests	-	-	-	(11.0)
Net income attributable to preferred share dividends of a	2.2	2.1	8.5	8.8
Net (loss) income attributable to Atlantic Power Corporation	($6.6)	($88.6)	($122.4)	($62.4)

[1] Includes Tunis and Moresby Lake

Cash Distributions from Projects, Q4 2016 vs Q4 2015 ($ millions)

Three months ended December 31, 2016 (Unaudited)

Unaudited	Project Adjusted EBITDA	Repayment of long-term debt	Interest expense, net	Capital expenditures	Other, including changes in working capital	Cash Distributions from Projects
Segment						
East U.S.						
Consolidated	$13.0	($3.0)	($2.1)	($1.3)	($0.1)	$6.6
Equity method	8.9	-	(0.4)	(0.1)	1.2	9.7
Total	21.9	(3.0)	(2.5)	(1.4)	1.1	16.3
West U.S.						
Consolidated	4.1	-	-	-	6.5	10.5
Equity method	3.6	-	-	(0.0)	(0.0)	3.6
Total	7.7	-	-	(0.0)	6.4	14.2
Canada						
Consolidated	12.6	(0.0)	(0.0)	(0.2)	2.9	15.3
Equity method	-	-	-	-	-	-
Total	12.6	(0.0)	(0.0)	(0.2)	2.9	15.3
Total consolidated	29.7	(3.0)	(2.1)	(1.5)	9.3	32.4
Total equity method	12.6	-	(0.4)	(0.1)	1.2	13.3
Un-allocated corporate	0.1	-	-	-	(0.1)	(0.0)
Total	$42.3	($3.0)	($2.5)	($1.6)	$10.3	$45.6

Three months ended December 31, 2015 (Unaudited)

	Project Adjusted EBITDA	Repayment of long-term debt	Interest expense, net	Capital expenditures	Other, including changes in working capital	Cash Distributions from Projects
Segment						
East U.S.						
Consolidated	$15.3	($4.3)	($2.0)	($0.3)	$0.9	$9.7
Equity method	8.3	-	(0.3)	(0.0)	0.1	8.2
Total	23.6	(4.3)	(2.2)	(0.4)	1.1	17.8
West U.S.						
Consolidated	6.3	-	-	-	3.3	9.5
Equity method	3.6	-	-	(0.0)	(0.2)	3.3
Total	9.9	-	-	(0.0)	3.0	12.9
Canada						
Consolidated	16.8	(0.1)	(0.0)	(0.9)	0.8	16.6
Equity method	-	-	-	-	-	-
Total	16.8	(0.1)	(0.0)	(0.9)	0.8	16.6
Total consolidated	38.4	(4.4)	(2.0)	(1.2)	5.0	35.8
Total equity method	11.9	-	(0.3)	(0.1)	(0.1)	11.5
Un-allocated corporate	0.1	-	-	0.0	(0.1)	(0.0)
Total	$50.4	($4.4)	($2.2)	($1.3)	$4.8	$47.3

Cash Distributions from Projects, FY 2016 vs FY 2015 ($ millions)

Twelve months ended December 31, 2016 (Unaudited)

Unaudited	Project Adjusted EBITDA	Repayment of long-term debt	Interest expense, net	Capital expenditures	Other, including changes in working capital	Cash Distributions from Projects
Segment						
East U.S.						
Consolidated	$52.7	($10.9)	($7.5)	($2.0)	$1.8	$34.1
Equity method	39.7	-	(1.6)	(0.3)	(0.7)	37.1
Total	92.4	(10.9)	(9.1)	(2.3)	1.1	71.2
West U.S.						
Consolidated	37.9	-	-	0.0	1.3	39.2
Equity method	13.2	-	-	(0.0)	1.3	14.6
Total	51.2	-	-	0.0	2.6	53.8
Canada						
Consolidated	58.8	(0.2)	(0.0)	(0.9)	3.2	60.9
Equity method	-	-	-	-	-	-
Total	58.8	(0.2)	(0.0)	(0.9)	3.2	60.9
Total consolidated	149.5	(11.0)	(7.5)	(3.0)	6.3	134.3
Total equity method	52.9	-	(1.6)	(0.3)	0.6	51.7
Un-allocated corporate	(0.2)	-	-	0.3	(0.2)	(0.1)
Total	$202.2	($11.0)	($9.1)	($2.9)	$6.7	$185.8

Twelve months ended December 31, 2015 (Unaudited)

	Project Adjusted EBITDA	Repayment of long-term debt	Interest expense, net	Capital expenditures	Other, including changes in working capital	Cash Distributions from Projects
Segment						
East U.S.						
Consolidated	$65.8	($14.9)	($8.5)	($7.6)	$2.8	$37.6
Equity method	39.0	-	(1.2)	(0.2)	3.7	41.3
Total	104.8	(14.9)	(9.7)	(7.8)	6.5	78.9
West U.S.						
Consolidated	33.6	-	-	(0.6)	1.0	33.9
Equity method	13.3	-	-	(0.1)	0.7	13.9
Total	46.9	-	-	(0.7)	1.6	47.9
Canada						
Consolidated	59.7	(0.3)	(0.0)	(3.4)	9.5	65.6
Equity method	-	-	-	-	-	-
Total	59.7	(0.3)	(0.0)	(3.4)	9.5	65.6
Total consolidated	159.1	(15.1)	(8.6)	(11.6)	13.3	137.1
Total equity method	52.3	-	(1.2)	(0.3)	4.4	55.3
Un-allocated corporate	(2.5)	-	-	0.2	2.2	(0.1)
Total	$208.9	($15.1)	($9.8)	($11.6)	$19.9	$192.2

Non-GAAP Disclosures

Project Adjusted EBITDA is not a measure recognized under GAAP and does not have a standardized meaning prescribed by GAAP, and is therefore unlikely to be comparable to similar measures presented by other companies. Investors are cautioned that the Company may calculate this non-GAAP measure in a manner that is different from other companies. The most directly comparable GAAP measure is Project income (loss). Project Adjusted EBITDA is defined as project income (loss) plus interest, taxes, depreciation and amortization (including non-cash impairment charges) and changes in the fair value of derivative instruments. Management uses Project Adjusted EBITDA at the project level to provide comparative information about project performance and believes such information is helpful to investors. A reconciliation of Project Adjusted EBITDA to Project income (loss) and to Net income (loss) by segment and on a consolidated basis is provided in slides 33-34.

Cash Distributions from Projects is the amount of cash distributed by the projects to the Company out of available project cash flow after all project-level operating costs, interest payments, principal repayment, capital expenditures and working capital requirements. It is not a non-GAAP measure. Project Adjusted EBITDA, a non-GAAP measure, is the most comparable measure, but it is before debt service, capital expenditures and working capital requirements. The Company has provided a bridge of Project Adjusted EBITDA to Cash Distributions from Projects in slides 35-36.

Investors are cautioned that the Company may calculate these measures in a manner that is different from other companies.

Unaudited

	Three months ended December 31		Twelve months ended December 31	
	2016	**2015**	**2016**	**2015**
Net (loss) income attributable to Atlantic Power Corporation	**($6.6)**	**($88.6)**	**($122.4)**	**($62.4)**
Net income attributable to preferred share dividends of a subsidiary company	2.2	1.9	8.5	8.8
Net (loss) attributable to noncontrolling interests	-	-	-	(11.0)
Net loss	($4.4)	($86.7)	($113.9)	($64.6)
Net income from discontinued operations, net of tax	-	1.3	-	(19.5)
Net income (loss) from continuing operations	**(4.4)**	**(85.4)**	**(113.9)**	**(84.1)**
Income tax expense	(0.4)	(29.9)	(14.6)	(30.4)
Income (loss) from continuing operations before income taxes	(4.8)	(115.3)	(128.5)	(114.5)
Administration	5.0	6.4	22.6	29.4
Interest expense, net	18.2	15.8	106.0	107.1
Foreign exchange loss	(5.1)	(11.2)	13.9	(60.3)
Other income, net	-	-	(3.9)	(3.1)
Project income (loss)	$13.3	($104.3)	$10.1	($41.4)
Reconciliation to Project Adjusted EBITDA				
Depreciation and amortization	$42.7	$31.2	$133.5	$130.1
Interest expense, net	2.7	2.1	10.9	9.8
Change in the fair value of derivative instruments	(17.8)	(6.7)	(37.9)	(15.4)
Impairment	1.2	127.8	85.9	127.8
Other (income) expense	0.2	0.3	(0.3)	(2.0)
Total Project Adjusted EBITDA	$42.3	$50.4	$202.2	$208.9

Reconciliation of Net Income (loss) to Project Adjusted EBITDA by Segment, Q4 2016 vs Q4 2015 ($ millions)

Three months ended December 31, 2016

	East U.S.	West U.S.	Canada	Un-allocated Corporate	Consolidated
Net (loss) income attributable to Atlantic Power Corporation	$14.3	($2.0)	($2.6)	($16.3)	($6.6)
Net income attributable to preferred share dividends of a subsidiary co	-	-	-	2.2	2.2
Net (loss) attributable to noncontrolling interests	-	-	-	-	-
Net (loss) income	14.3	(2.0)	(2.6)	(14.1)	(4.4)
Net income from discontinued operations, net of tax	-	-	-	-	-
Net income (loss) from continuing operations	14.3	(2.0)	(2.6)	(14.1)	(4.4)
Income tax (benefit) expense	-	-	-	(0.4)	(0.4)
Income (loss) from continuing operations before income taxes	14.3	(2.0)	(2.6)	(14.5)	(4.8)
Administration	-	-	-	5.0	5.0
Interest expense, net	-	-	-	18.2	18.2
Foreign exchange loss (gain)	-	-	-	(5.0)	(5.0)
Other income, net	-	-	-	-	-
Project income (loss)	14.3	(2.0)	(2.6)	3.6	13.3
Change in fair value of derivative instruments	(6.2)	-	(7.8)	(3.8)	(17.8)
Depreciation and amortization	11.1	9.7	21.8	0.1	42.7
Interest expense, net	2.7	-	-	-	2.7
Impairment	-	-	1.2	-	1.2
Other project expense	-	-	-	0.2	0.2
Project Adjusted EBITDA	$21.9	$7.7	$12.6	$0.1	$42.3

Three months ended December 31, 2015

	East U.S.	West U.S.	Canada	Un-allocated Corporate	Consolidated
Net (loss) income attributable to Atlantic Power Corporation	($1.3)	$0.3	($103.6)	$16.0	($88.6)
Net income attributable to preferred share dividends of a subsidiary co	-	-	-	2.1	2.1
Net (loss) attributable to noncontrolling interests	-	-	-	-	-
Net (loss) income	(1.3)	0.3	(103.6)	18.1	(86.5)
Net income from discontinued operations, net of tax	-	-	-	1.1	1.1
Net income (loss) from continuing operations	(1.3)	0.3	(103.6)	19.2	(85.4)
Income tax (benefit) expense	-	-	-	(29.9)	(29.9)
Income (loss) from continuing operations before income taxes	(1.3)	0.3	(103.6)	(10.7)	(115.3)
Administration	-	-	-	6.4	6.4
Interest expense, net	-	-	-	15.8	15.8
Foreign exchange loss (gain)	-	-	-	(11.2)	(11.2)
Other income, net	-	-	-	-	-
Project income (loss)	(1.3)	0.3	(103.6)	0.3	(104.3)
Change in fair value of derivative instruments	(1.7)	-	(4.4)	(0.7)	(6.8)
Depreciation and amortization	10.6	9.7	10.8	0.2	31.3
Interest expense, net	2.2	-	(0.1)	-	2.1
Other project expense	13.8	(0.1)	114.1	0.4	128.2
Project Adjusted EBITDA	$23.6	$9.9	$16.8	$0.1	$50.4

Reconciliation of Net Income (loss) to Project Adjusted EBITDA by Segment, FY 2016 vs FY 2015 ($ millions)

Twelve months ended December 31, 2016

	East U.S.	West U.S.	Canada	Un-allocated Corporate	Consolidated
Net (loss) income attributable to Atlantic Power Corporation	$31.2	$11.8	($35.7)	($129.7)	($122.4)
Net income attributable to preferred share dividends of a subsidiary co	-	-	-	8.5	8.5
Net (loss) attributable to noncontrolling interests	-	-	-	-	-
Net (loss) income	31.2	11.8	(35.7)	(121.2)	(113.9)
Net income from discontinued operations, net of tax	-	-	-	-	-
Net income (loss) from continuing operations	31.2	11.8	(35.7)	(121.2)	(113.9)
Income tax (benefit) expense	-	-	-	(14.6)	(14.6)
Income (loss) from continuing operations before income taxes	31.2	11.8	(35.7)	(135.8)	(128.5)
Administration	-	-	-	22.6	22.6
Interest, net	-	-	-	106.0	106.0
Foreign exchange loss (gain)	-	-	-	13.9	13.9
Other income, net	-	-	-	(3.9)	(3.9)
Project income (loss)	31.2	11.8	(35.7)	2.8	10.1
Change in fair value of derivative instruments	(9.2)	-	(25.5)	(3.2)	(37.9)
Depreciation and amortization	44.1	39.4	49.5	0.5	133.5
Interest, net	10.9	-	-	-	10.9
Impairment	15.4	-	70.5	-	85.9
Other project expense	-	-	-	(0.3)	(0.3)
Project Adjusted EBITDA	$92.4	$51.2	$58.8	($0.2)	$202.2

Twelve months ended December 31, 2015

	East U.S.	West U.S.	Canada	Un-allocated Corporate	Consolidated
Net (loss) income attributable to Atlantic Power Corporation	$38.7	$7.6	($85.7)	($23.0)	($62.4)
Net income attributable to preferred share dividends of a subsidiary co	-	-	-	8.8	8.8
Net (loss) attributable to noncontrolling interests	-	-	-	(11.0)	(11.0)
Net (loss) income	38.7	7.6	(85.7)	(25.2)	(64.6)
Net income from discontinued operations, net of tax	-	-	-	(19.5)	(19.5)
Net income (loss) from continuing operations	38.7	7.6	(85.7)	(44.7)	(84.1)
Income tax (benefit) expense	-	-	-	(30.4)	(30.4)
Income (loss) from continuing operations before income taxes	38.7	7.6	(85.7)	(75.1)	(114.5)
Administration	-	-	-	29.4	29.4
Interest, net	-	-	-	107.1	107.1
Foreign exchange loss (gain)	-	-	-	(60.3)	(60.3)
Other income, net	-	-	-	(3.1)	(3.1)
Project income (loss)	38.7	7.6	(85.7)	(2.0)	(41.4)
Change in fair value of derivative instruments	-	-	(16.0)	0.6	(15.4)
Depreciation and amortization	42.5	39.3	47.2	1.1	130.1
Interest, net	9.8	-	-	-	9.8
Other project expense	13.8	-	114.2	(2.2)	125.8
Project Adjusted EBITDA	$104.8	$46.9	$59.7	($2.5)	$208.9