Enbridge Energy Partners

Third Quarter 2017 Supplemental Slides

Enbridge Energy Partners, L.P.

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"Enbridge" refers collectively to Enbridge Inc. and its subsidiaries other than the Partnership and its subsidiaries.
Except to the extent required by law, the Partnership assumes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. Reference should also be made to the Partnership's filings with the U.S. Securities and Exchange Commission (the "SEC"), including its most recently filed Annual Report on Form 10-K and any subsequently filed Quarterly Reports on Form 10-Q or current reports on Form 8-K for additional factors that may affect results. These filings are available to the public over the Internet at the SEC's website (www.sec.gov) and at the Partnership's website.

Enbridge Energy Partners (EEP): Adjusted EBITDA to Distributable Cash Flow

ENBRIDGE Energy Partners, L.P.

(US$ Millions)	3Q16	3Q17
Adjusted EBITDA	456.8	**426.2**
Interest Expense (Net)[1]	(105.7)	**(97.2)**
Income Tax Expense	(2.2)	**(0.1)**
Distributions in excess of equity earnings	3.0	**3.2**
Maintenance capital expenditures	(15.8)	**(10.4)**
Noncontrolling interests	(119.1)	**(115.9)**
Make-up rights adjustment	0.1	**-**
Allowance for equity used during construction[2]	-	**(12.2)**
Distribution support agreement[3]	(2.4)	**-**
Distributable Cash Flow	214.7	**193.6**

(1) Excludes unrealized mark-to-market net losses of $0.3 million for the three months ended September 30, 2017. Also excludes $6.6 million of amortization related to pre-issuance interest swaps for the three months ended September 30, 2017 and September 30, 2016.
(2) Beginning Q1 2017 distributable cash flow excludes allowance for equity used during construction .
(3) Distribution agreement in place with Midcoast Energy Partners (MEP) to support 1.0x coverage of the then declared distribution with a term through 2017, and no requirement for MEP to reimburse EEP for adjusted distributions.

Adjusted EBITDA and Distributable Cash Flow (DCF) are non-GAAP measures. Reconciliations to GAAP measures can be found in the supplemental slides available at www.enbridgepartners.com

EEP Unit Structure
as of September 30, 2017

ENBRIDGE Energy Partners, L.P.

(Millions of units)

Unit Class[1]	ENB[5]	Public	TOTAL
Cash Paying LP units[2]			
A	110.8	215.7	326.5
B	7.8	-	7.8
E	18.1	-	18.1
EEQ PIK **Shares**[4]	10.2	77.4	87.6
Incentive units – Class F[6]	-	-	-
TOTAL	**146.9**	**293.1**	**440.0**
Economic Interest[3]	**34.7%**	**65.3%**	

(1) Does not include 2% GP interest
(2) All limited partner units receive the same US $1.40 annualized distribution
(3) Includes GP Interest
(4) Enbridge Energy Management, L.L.C. (EEQ) Listed Shares outstanding equals the number of I-units issued by EEP, all of which i-units are owned by EEQ
(5) Unless otherwise specified, units are owned by Enbridge Energy Company, Inc. or its wholly-owned subsidiaries
(6) 1,000 Class F units outstanding

Low-Risk "Utility-Like" Business

Reliable Business Model Provides Highly Predictable Cash Flows

Stable Business

~96%

of cash flow underpinned by long term cost of service or equivalent[1] and take or pay agreements

Investment Grade Customers

~100%

of revenue from investment grade or equivalent customers

Direct Commodity Exposure (CFaR)[2]

<1%

of cash flow directly subject to commodity price fluctuations

[1] Contract terms for our Lakehead system expansion projects mitigate volume risk for all expansions subsequent to Alberta Clipper. In the event volumes were to decline by approximately 500Kbpd from current levels out of the Superior, Wisconsin terminal, Lakehead could be subject to volume risk, however, the pipeline could potentially file cost of service rates if there was a substantial divergence between costs and revenues mitigating volume risk. Similarly, our North Dakota system can also file cost of service rates if there is a substantial divergence between costs and revenues on the pipeline.

[2] Cash Flow at Risk is a statistical measure of the maximum adverse change in projected 12-month cash flow that could occur as a result of movements in market prices (over a one-month holding period) with a 97.5% level of confidence; exposure is predominately oil loss allowance.

Investor Value Proposition

Attractive long term risk-return proposition

Low risk, pure-play liquids pipeline MLP provides attractive risk-adjusted returns for unitholders

Pure-play liquids pipeline MLP

- Exceptional North American liquids infrastructure
- Low-risk commercial agreements
- Competitive and stable tolls

Low risk business model

- ~96% cost of service or equivalent[1] and take or pay agreements
- ~100% of revenue from investment grade or equivalent customers
- No direct commodity price exposure

Prudent financial management

- Commitment to investment grade balance sheet
- Healthy 1.2x distribution coverage targeted

Moderate visible growth

- Secured through embedded organic growth and JFAs
- Sustainable growth with strong coverage

[1] Contract terms for our Lakehead system expansion projects mitigate volume risk for all expansions subsequent to Alberta Clipper. In the event volumes were to decline by approximately 500Kbpd from current levels out of the Superior, Wisconsin terminal, Lakehead could be subject to volume risk, however, the pipeline could potentially file cost of service rates if there was a substantial divergence between costs and revenues mitigating volume risk. Similarly, our North Dakota system can also file cost of service rates if there is a substantial divergence between costs and revenues on the pipeline.

Supplemental Schedules

Third Quarter Earnings
(GAAP)

	Three Months Ended September 30, 2017	2016	Change
Segmented and other operating income (loss):			
-Liquids	$ 267.9	$ (446.8)	$ 714.7
-Other	(1.7)	(2.3)	0.6
Operating income (loss)	266.2	(449.1)	715.3
Other income	21.8	0.6	21.2
Allowance for equity used during construction	12.2	10.0	2.2
Interest expense, net	(104.1)	(103.4)	(0.7)
Income tax expense	(0.1)	(1.6)	1.5
Net income (loss) from continuing operations, net of tax	196.0	(543.5)	739.5
Loss from discontinued operations, net of tax	—	(31.1)	31.1
Net income (loss)	196.0	(574.6)	770.6
Less: Net income attributable to:			
Noncontrolling interest	102.9	(191.9)	294.8
Series 1 preferred unit distributions	—	22.5	(22.5)
Accretion of discount on Series 1 preferred units	—	1.2	(1.2)
Net income (loss) attributable to general and limited partner ownership in EEP	$ 93.1	$ (406.4)	$ 499.5
Net income (loss) allocable to common units and i-units			
Income (loss) from continuing operations	$ 82.0	$ (432.7)	$ 514.7
Income (loss) from discontinued operations	—	(19.9)	19.9
Net income (loss) allocable to common units and i-units	$ 82.0	$ (452.6)	$ 534.6
Net income (loss) per common unit and i-unit (basic and diluted)			
Income (loss) from continuing operations	$ 0.19	$ (1.25)	$ 1.44
Income (loss) from discontinued operations	—	(0.06)	0.06
Net income (loss) per common unit and i-unit	$ 0.19	$ (1.31)	$ 1.50
Weighted average common units and i-units outstanding	421.0	349.1	71.9

(unaudited; in millions, except per unit amounts)

Third Quarter Earnings
(Adjusted)

	Three Months Ended September 30,		
Segmented and other operating income (loss):	2017	2016	Change
-Liquids	$ 282.1	$ 304.0	$ (21.9)
-Other	(1.7)	(2.3)	0.6
Operating income (1)	280.4	301.7	(21.3)
Other income	21.8	0.6	21.2
Allowance for equity used during construction	12.2	10.0	2.2
Interest expense, net (1)	(103.8)	(103.4)	(0.4)
Income tax expense	(0.1)	(1.6)	1.5
Loss from discontinued operations, net of tax	—	(13.6)	13.6
Less: Net income attributable to:			
Noncontrolling interest	(101.2)	(81.9)	(19.3)
Series 1 preferred unit distributions	—	(22.5)	22.5
Net income attributable to general and limited partner ownership in EEP (1)	109.3	89.3	20.0
Allocations to general partner	(12.2)	(56.1)	43.9
Net income allocable to common units and i-units (1)	97.1	33.2	63.9
Weighted average common units and i-units outstanding (basic and diluted)	421.0	349.1	71.9
Net income per common unit and i-unit (basic and diluted)(2)	$ 0.24	$ 0.09	$ 0.15
EBITDA (1)	$ 426.2	$ 456.8	$ (30.6)

(unaudited; in millions, except per unit amounts)

(1) Excludes the impact of: (a) non-cash, mark-to-market net gains and losses; (b) Integration costs (c) gains on sale of assets of $5.5 million; (d) environmental costs, net of insurance recoveries, associated with the Line 6A & 6B incident; (e) Line 2 hydro test expenses, net of recoveries; and other adjustments - see non-GAAP reconciliations.

(2) Calculated based on the two class MLP method. Calculation factors in common units' and i-units' share (98%) of distributions in excess of earnings divided by the weighted average number of common units and i-units outstanding for the period . The overdistributed earnings are allocated to the common units and i-units based on the distribution waterfall that is outlined in our partnership agreement.

Distribution Coverage

	As declared Q3 2017	As paid Q3 2017	As declared YTD 2017	As paid YTD 2017
Net income attributable to general and limited partner ownership in EEP	$ 93.1	$ 93.1	$ 251.2	$ 251.2
Noncash derivatives fair value (gains) losses	2.0	2.0	(10.8)	(10.8)
Accretion of discount on Series 1 preferred units	—	—	8.5	8.5
Severance costs	—	—	7.6	7.6
Integration Costs	17.2	17.2	18.0	18.0
Sandpiper wind down costs	0.4	0.4	4.3	4.3
Gain on sale of assets	(3.4)	(3.4)	(35.7)	(35.7)
Adjusted net income	109.3	109.3	243.1	243.1
Series 1 preferred unit distributions	—	—	29.0	29.0
Depreciation and amortization (3)	93.0	93.0	328.8	328.8
Distribution in excess of income from Joint Ventures	3.2	3.2	3.3	3.3
Maintenance capital expenditures	(10.4)	(10.4)	(26.2)	(26.2)
Allowance for equity used during construction (net of NCI)	(1.5)	(1.5)	(5.5)	(5.5)
Ship or Pay Contract	—	—	1.3	1.3
Distributable Cash Flow (1)	$ 193.6	$ 193.6	$ 573.8	$ 573.8
Cash Distributions	129.7	129.6	388.9	475.3
PIK Distributions (gross) (2)	31.2	30.6	91.9	109.3
Total Distributions	$ 160.9	$ 160.2	$ 480.8	$ 584.6
Cash Coverage Ratio	1.49	1.49	1.48	1.21
Coverage Ratio	1.20	1.21	1.19	0.98
Distribution per unit	$ 0.3500	$ 0.3500	$ 1.0500	$ 1.2830

(unaudited; in millions)

(1) See non-GAAP reconciliation tables.
(2) Notional value of paid in kind distributions.
(3) Inclusive of $6.6 million and $19.9 million of amortization related to pre-issuance interest swaps.

Segment Operating Income
(Adjusted)

Liquids	Three Months Ended September 30, 2017	2016	Change
Operating revenue [1]	$ 618.3	$ 634.2	$ (15.9)
Power	(80.1)	(74.3)	(5.8)
Environmental costs [1]	(1.2)	—	(1.2)
Operating and administrative expenses [1]	(143.1)	(146.5)	3.4
Depreciation and amortization	(111.8)	(109.4)	(2.4)
Adjusted operating income [1]	$ 282.1	$ 304.0	$ (21.9)

(unaudited; in millions)

(1) Excludes the impact of: (a) non-cash, mark-to-market net gains and losses; (b) Integration costs (c) gains on sale of assets of $5.5 million; (d) environmental costs, net of insurance recoveries, associated with the Line 6A & 6B incident; (e) Line 2 hydro test expenses, net of recoveries; and other adjustments - see non-GAAP reconciliations.

Net Loss from Discontinued Operations
(Adjusted)

Discontinued Operations	Three Months Ended September 30, 2017	2016	Change
Net loss from discontinued operations	$ —	$ (31.1)	$ 31.1
Noncash derivative fair value losses	—	11.1	(11.1)
Loss on sale of non-core assets	—	1.6	(1.6)
Severance costs	—	0.6	(0.6)
Adjusted net loss from discontinued operations (1)	$ —	$ (17.8)	$ 17.8

(unaudited; in millions)

(1) Excludes the impact of non-cash, mark-to-market net gains and losses and other adjustments - see non-GAAP reconciliations.

Liquids Operating Income
(Adjusted)

Liquids Adjusted Operating Income	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Change
Lakehead	$ 255.7	$ 252.1	$ 3.6
Mid-Continent	8.3	20.5	(12.2)
North Dakota (1)	18.1	31.4	(13.3)
Liquids adjusted operating income (2)	$ 282.1	$ 304.0	$ (21.9)

(unaudited; in millions)

(1) Operating income for North Dakota does not include the $21.7 million of equity income from the Bakken Pipeline System. This is included in other income.
(2) Excludes the impact of non-cash, mark-to-market net gains and losses, transition costs, gains on sale of assets of $5.5 million and other adjustments - see non-GAAP reconciliations.

Lakehead Operating Income
(Adjusted)

Lakehead Adjusted Operating Income	Three Months Ended September 30, 2017	2016	Change
Operating revenue [1]	$ 546.3	$ 524.8	$ 21.5
Power	(72.4)	(63.1)	(9.3)
Operating and administrative expenses [1]	(119.7)	(115.1)	(4.6)
Depreciation and amortization	(98.5)	(94.5)	(4.0)
Adjusted operating income [1]	$ 255.7	$ 252.1	$ 3.6

(unaudited; in millions)

(1) Excludes the impact of non-cash, mark-to-market net gains and losses and transition costs - see non-GAAP reconciliations.

Mid-Continent Operating Income
(Adjusted)

Mid-Continent Adjusted Operating Income	Three Months Ended September 30, 2017	2016	Change
Operating revenue [1]	$ 22.2	$ 42.9	$ (20.7)
Power	(0.4)	(2.6)	2.2
Environmental costs [1]	(1.2)	—	(1.2)
Operating and administrative expenses [1]	(8.4)	(14.4)	6.0
Depreciation and amortization	(3.9)	(5.4)	1.5
Adjusted operating income [1]	$ 8.3	$ 20.5	$ (12.2)

(unaudited; in millions)

(1) Excludes the impact of non-cash, mark-to-market net gains and losses and other adjustments - see non-GAAP reconciliations.

North Dakota Operating Income
(Adjusted)

North Dakota Adjusted Operating Income	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Change
Operating revenue [1]	$ 49.8	$ 66.5	$ (16.7)
Power	(7.3)	(8.6)	1.3
Operating and administrative expenses [1]	(15.0)	(17.0)	2.0
Depreciation and amortization	(9.4)	(9.5)	0.1
Adjusted operating income [1]	$ 18.1	$ 31.4	$ (13.3)

(unaudited; in millions)

(1) Excludes the impact of non-cash, mark-to-market net gains and losses and gain on sale of $5.5 million and other adjustments - see non-GAAP reconciliations.

Capital Expenditures

	Q3 2017	YTD 2017
Maintenance Capex	$ 10.4	$ 30.2
Enhancement Capex [1][2][3]	$ 199.9	$ 387.4
Ending PP&E, net	$ 12,820.1	$ 12,820.1

Q3 2017 Major Enhancement Expenditures

	Q3 2017	YTD 2017
Eastern Access [1]	$ 9.6	$ 13.1
Mainline Expansion [2]	$ 24.5	$ 87.7
Line 3 Replacement [3]	$ 119.0	$ 207.8

(unaudited; in millions)

(1) Enhancement expenditure is before Eastern Access joint funding, with 60% to be funded by Enbridge, Inc.

(2) Enhancement expenditure is before Mainline Expansion joint funding, with 75% to be funded by Enbridge, Inc.

(3) Enhancement expenditure is before Line 3 Replacement joint funding, with 99% to be funded by Enbridge, Inc.

Book Capitalization

	September 30, 2017	December 31, 2016
Short-term debt	$ 399.8	$ —
Long-term debt (1)	6,091.1	6,865.9
Total debt	$ 6,490.9	$ 6,865.9
Partners' capital (1)	7,201.9	8,058.9
Total capitalization	$ 13,692.8	$ 14,924.8
Total debt / Total capitalization	47.4 %	46.0 %

	September 30, 2017	December 31, 2016
Amounts outstanding under Credit Facilities	$ 744.0	$ 2,015.1
Principal amount of Commercial Paper issuances	1,080.5	392.5
Letters of Credit outstanding	65.3	121.1
Amount we could borrow	1,485.2	846.3
Total credit under Credit Facilities (2)	$ 3,375.0	$ 3,375.0

(unaudited; in millions)

(1) Debt reduced and Partners' Capital increased in 2017 and 2016 by $200 million for Junior Subordinated Notes' equity credit. Partners' Capital excludes Accumulated Other Comprehensive Income and includes Noncontrolling Interest.

(2) Comparative information excludes discontinued operations.

Volume History

	Q3 2015	Q4 2015	Q1 2016	Q2 2016	Q3 2016	Q4 2016	Q1 2017	Q2 2017	Q3 2017
Liquids Business - Volumes (kbpd)									
Lakehead	2,338	2,388	2,735	2,440	2,495	2,624	2,748	2,604	2,620
Mid-Continent	216	213	168	216	217	153	145	—	—
North Dakota	333	375	402	381	363	364	334	355	303
Total	2,887	2,976	3,305	3,037	3,075	3,141	3,227	2,959	2,923
Natural Gas Business - Volumes ('000 MMbtu/d)									
East Texas	966	915	948	931	894	843	848	908	—
Anadarko	760	707	652	637	606	570	495	516	—
North Texas	262	239	214	201	192	182	175	172	—
Total	1,988	1,861	1,814	1,769	1,692	1,595	1,518	1,596	—
Natural Gas Processing - Volumes ('000 mcf/d)									
East Texas	519	510	509	505	447	442	454	438	—
Anadarko	593	551	516	505	474	448	387	388	—
North Texas	173	161	142	131	125	121	115	115	—
Total	1,285	1,222	1,167	1,141	1,046	1,011	956	941	—
NGL Production -Volumes (bpd)									
Total	85,343	79,064	73,499	71,747	67,588	62,621	61,661	63,887	—

Non-GAAP Reconciliations

Reconciliations of forward looking non-GAAP financial measures to comparable GAAP measures are not available due to the challenges with estimating some of the items, particularly with estimating non-cash unrealized derivative fair value losses and gains, which are subject to market variability, and therefore a reconciliation is not available without unreasonable effort. Non-GAAP measures no longer include make-up rights and option premium amortization adjustments. These changes were made on a prospective basis beginning with the second quarter of 2016 and are not material for historical periods presented.

Adjusted Earnings

- The foregoing presentation makes reference to adjusted net income in order to exclude the effect of non-cash and other items that we believe are not indicative of our core operating results. A reconciliation to net income per GAAP is provided below.

Adjusted Net Income	Three months ended September 30,		Nine months ended September 30,	
(unaudited; in millions, except per unit amounts)	2017	2016	2017	2016
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 93.1	$ (406.4)	$ 251.2	$ (242.7)
Noncash derivative fair value (gains) losses:				
-Liquids	1.7	0.2	(1.0)	7.0
-Natural Gas - included in Discontinued Operations	—	11.1	(12.0)	66.6
-Other	0.3	—	2.2	3.4
Accretion of discount on Series 1 preferred units	—	1.2	8.5	3.5
Make-up rights adjustment	—	—	—	1.0
Line 2 hydrotest expenses, net of recoveries	—	(2.0)	—	(10.3)
Line 6A and 6B incident expenses, net of recoveries	—	(10.0)	—	6.0
Option premium amortization	—	—	—	0.9
Sandpiper Project wind down costs	0.4	3.7	4.3	3.7
Gain on sale of assets	(3.4)	1.6	(35.7)	1.6
Severance costs	—	0.6	7.6	0.6
Asset impairment	—	489.3	—	497.4
Integration Costs	17.2	—	18.0	—
Adjusted net income	109.3	89.3	243.1	338.7
Less: Allocations to general partner	12.2	56.1	34.9	169.7
Adjusted net income allocable to common units and i-units	97.1	33.2	208.2	169.0
Weighted average common units and i-units outstanding	421.0	349.1	391.6	347.0
Adjusted net income per common unit and i-unit (basic and diluted)	$ 0.24	$ 0.09	$ 0.54	$ 0.48

(unaudited; in millions)

Adjusted Segment Operating Income

- The foregoing presentation makes reference to adjusted operating income, which is reconciled to nearest comparable GAAP measures as shown below.

Liquids	Q3 2017	Q3 2016
Operating income	$ 267.9	$ (446.8)
Noncash derivative fair value losses	1.7	0.2
Line 2 hydrotest expenses, net of recoveries	—	(2.0)
Line 6A and 6B incident expenses, net of recoveries	—	(10.0)
Gain on sale of assets	(5.5)	—
Sandpiper Project wind down costs	0.8	5.9
Asset impairment	17.2	756.7
Adjusted operating income	$ 282.1	$ 304.0

(unaudited; in millions)

Adjusted Segment EBITDA

ENBRIDGE Energy Partners, L.P.

- A reconciliation of segment adjusted operating income to Adjusted EBITDA is provided below.

	Three Months Ended September 30,	
Segmented and other adjusted operating income (loss):	2017	2016
Liquids	$ 282.1	$ 304.0
Other	(1.7)	(2.3)
Adjusted operating income	280.4	301.7
Other income	21.8	0.6
Allowance for equity used during construction	12.2	10.0
Depreciation and amortization	111.8	109.4
Adjusted operating loss from discontinued operations	—	(12.2)
Depreciation and amortization and other income - discontinued operations	—	47.3
Adjusted EBITDA	$ 426.2	$ 456.8

(unaudited; in millions)

Adjusted EBITDA

Enbridge Energy Partners, L.P.

- The foregoing presentation makes reference to adjusted EBITDA which is used as a supplemental financial measurement to manage the performance of the entity. A reconciliation of net income to adjusted EBITDA is provided below.

Adjusted EBITDA	Three months ended September 30, 2017	Three months ended September 30, 2016	Nine months ended September 30, 2017	Nine months ended September 30, 2016
(unaudited; in millions)	2017	2016	2017	2016
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 93.1	$ (406.4)	$ 251.2	$ (242.7)
Net income attributable to noncontrolling interest	102.9	(191.9)	261.8	(52.8)
Series 1 preferred unit distributions	—	22.5	29.0	67.5
Accretion of discount on Series 1 preferred units	—	1.2	8.5	3.5
Interest expense, income tax expense, and depreciation and amortization - discontinued operations	—	48.7	92.9	146.2
Interest expense, net	104.1	103.4	305.8	301.2
Income tax expense (benefit)	0.1	1.6	(0.4)	5.2
Depreciation and amortization	111.8	109.4	328.9	315.7
Noncash derivative fair value (gains) losses	1.7	14.8	(16.9)	94.5
Make-up rights adjustment	—	—	—	1.0
Line 2 hydrotest expense, net of recoveries	—	(2.0)	—	(10.3)
Line 6A and 6B incident expenses, net of recoveries	—	(10.0)	—	6.0
Option premium amortization	—	—	—	1.2
Loss on sale of non-core assets	—	2.1	—	2.1
Gain on sale of assets	(5.5)	—	(57.0)	—
Sandpiper project wind down costs	0.8	5.9	7.1	5.9
Severance costs	—	0.8	8.2	0.8
Integration costs	17.2	—	18.0	—
Asset impairment	—	756.7	—	756.7
Asset impairment - discontinued operations	—	—	—	10.6
Adjusted EBITDA	$ 426.2	$ 456.8	$ 1,237.1	$ 1,412.3

Distributable Cash Flow

ENBRIDGE
Energy Partners, L.P.

- The foregoing presentation makes reference to distributable cash flow, which is used as a supplemental financial measurement to assess liquidity and the ability to generate cash sufficient to pay interest costs and make cash distributions to unitholders. A reconciliation of net cash provided by operating activities to distributable cash flow is provided below.

Distributable Cash Flow	Three months ended September 30,		Nine months ended September 30,	
(unaudited; in millions)	2017	2016	2017	2016
Total net cash provided by operating activities	$ 345.1	$ 414.6	$ 388.8	$ 961.1
Changes in operating assets and liabilities,				
net of cash acquired	(35.2)	(73.3)	511.8	120.7
Allowance for equity used during construction[1]	—	10.1	—	35.7
Option premium amortization	—	—	—	1.2
Line 2 hydrotest expense, net of recoveries	—	(2.0)	—	(10.3)
Distributions in excess of equity earnings	3.2	3.0	3.3	5.7
Maintenance capital expenditures	(10.4)	(15.8)	(26.2)	(35.5)
Noncontrolling interests	(115.9)	(119.1)	(307.0)	(345.4)
Gain on sale of assets	—	—	10.6	—
Distribution support agreement[2]	—	(2.4)	—	(3.8)
Other	6.8	(0.4)	(7.5)	(7.5)
Distributable cash flow	$ 193.6	$ 214.7	$ 573.8	$ 721.9

(1) Distributable cash flow excludes allowance for equity used during construction beginning Q1 2017.

(2) Distribution agreement in place with MEP to support 1.0x coverage of the then declared distribution with a term through 2017, and no requirement for MEP to reimburse EEP for adjusted distributions.

Adjusted EBITDA to DCF

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- A reconciliation of adjusted EBITDA to distributable cash flow is provided below.

Distributable Cash Flow	Three months ended September 30, 2017	Three months ended September 30, 2016	Nine months ended September 30, 2017	Nine months ended September 30, 2016
Adjusted EBITDA	$ 426.2	$ 456.8	$ 1,237.1	$ 1,412.3
Interest expense, net (1)	(97.2)	(105.7)	(301.1)	(303.4)
Income tax expense	(0.1)	(2.2)	(0.5)	(7.2)
Distributions in excess of equity earnings	3.2	3.0	3.3	5.7
Maintenance capital expenditures	(10.4)	(15.8)	(26.2)	(35.5)
Noncontrolling interests	(115.9)	(119.1)	(307.0)	(345.4)
Make-up rights adjustment	—	0.1	—	(0.8)
Allowance for equity used during construction (2)	(12.2)	—	(33.2)	—
Distribution support agreement (3)	—	(2.4)	—	(3.8)
Other	—	—	1.4	—
Distributable cash flow	$ 193.6	$ 214.7	$ 573.8	$ 721.9

(unaudited; in millions)

(1) Excludes unrealized mark-to-market net losses of $0.3 million and $2.2 million for the three and nine months ended September 30, 2017, respectively. Excludes unrealized mark-to-market net losses of $3.4 million for the nine months ended September 30, 2016. Also excludes $6.6 million and $19.9 million of amortization related to pre-issuance interest swaps for the three and nine months ended September 30, 2017 and September 30, 2016.

(2) Distributable cash flow excludes allowance for equity used during construction beginning Q1 2017.

(3) Distribution agreement in place with MEP to support 1.0x coverage of the then declared distribution with a term through 2017, and no requirement for MEP to reimburse EEP for adjusted distributions.