DYNEGY

Fourth Quarter and 2015 Full Year Review

February 24, 2016

Forward-Looking Statements

Cautionary Statement Regarding Forward-Looking Statements

This presentation contains statements reflecting assumptions, expectations, projections, intentions or beliefs about future events that are intended as "forward looking statements." You can identify these statements by the fact that they do not relate strictly to historical or current facts. Management cautions that any or all of Dynegy's forward-looking statements may turn out to be wrong. Please read Dynegy's annual, quarterly and current reports filed under the Securities Exchange Act of 1934, including its 2015 Form 10-K, when filed, for additional information about the risks, uncertainties and other factors affecting these forward-looking statements and Dynegy generally. Dynegy's actual future results may vary materially from those expressed or implied in any forward-looking statements. All of Dynegy's forward-looking statements, whether written or oral, are expressly qualified by these cautionary statements and any other cautionary statements that may accompany such forward-looking statements. In addition, Dynegy disclaims any obligation to update any forward-looking statements to reflect events or circumstances after the date hereof.

Non-GAAP Financial Measures

This presentation contains non-GAAP financial measures including EBITDA, Adjusted EBITDA and Free Cash Flow. Reconciliations of these measures to the most directly comparable GAAP financial measures to the extent available without unreasonable effort are contained herein. To the extent required, statements disclosing the definitions, utility and purposes of these measures are set forth in Item 2.02 to our current report on Form 8-K filed with the SEC on February 24, 2016, which is available on our website free of charge, www.dynegy.com.

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Overview and Outlook

2015 Financial Performance

- 2015 Adjusted EBITDA of $850 MM versus $347 MM in 2014
- Acquired assets contributed $590 MM to 2015 Adjusted EBITDA
- 2015 Free Cash Flow of $186 MM versus $104 MM in 2014
- 2015 results within guidance ranges

Environmental Compliance Update

- Environmental engineering studies completed in 4Q15
- Incorporated final ELG ruling to include all coal units
- $129 MM improvement in total cost estimate versus Dynegy's 2015 Investor Day

Portfolio / Commercial Updates

- Annual production records set at all PJM CCGTs in 2015
- $178 MM in PY 16/17 MISO capacity revenues secured; ~2,180 MW of capacity remains available for sale
- $188 MM in capacity revenues secured during ISO-NE FCA-10

2016 Outlook

- 2016 Adjusted EBITDA guidance range updated to $1,000 – 1,200 MM from $1,100 – 1,300 MM
- 2016 Free Cash Flow guidance range updated to $200 – 400 MM from $300 – 500 MM

Note: Adjusted EBITDA and Free Cash Flow are non-GAAP measures; reconciliations to GAAP can be found in the Appendix

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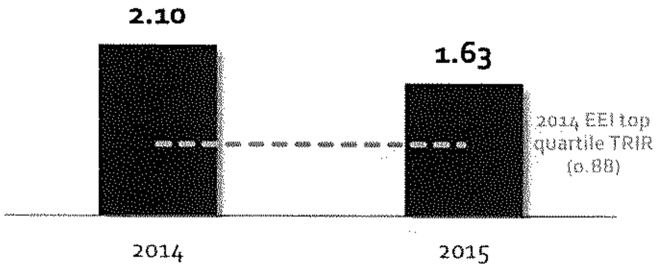
2015 Results and Updated 2016 Guidance

OPERATIONAL

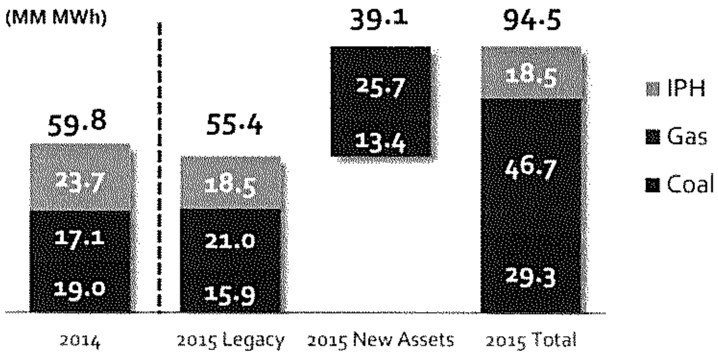
Safety Performance[1]

Total Recordable Incident Rate (TRIR)



- Gas Segment 2015 performance at top decile (.80)
- 2015 TRIR for the legacy Dynegy fleet was 1.35
- Half of Dynegy's CCGT fleet has achieved OSHA Voluntary Protection Program (VPP) designation (several others in progress)

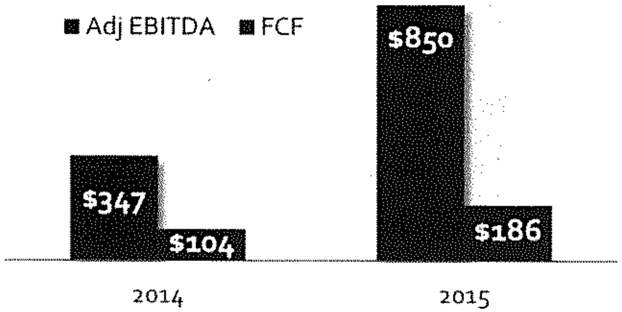
Volumes Generated[1]



- Legacy Gas Segment volumes increased primarily due to improved spark spreads at Kendall
- Legacy Coal Segment volumes decreased due to more planned outages and mild temperatures
- IPH volumes decreased due to mild temperatures

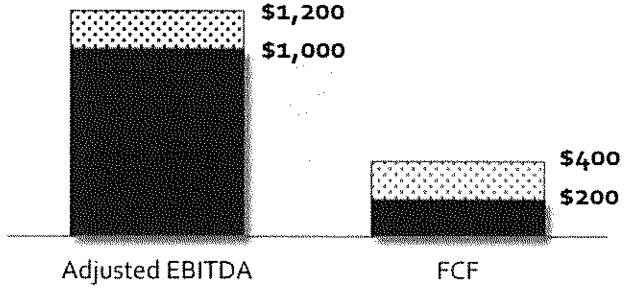
FINANCIAL

Adjusted EBITDA and FCF ($ MM)



- Gains primarily driven by new assets
- Higher capacity sales at IPH also contributed to gains

Updated 2016 Adjusted EBITDA and FCF Guidance ($ MM)



- 2016 Adjusted EBITDA and FCF guidance ranges updated due to weaker than expected margins across the fleet except PJM gas
- Previous Adjusted EBITDA and FCF guidance ranges of $1,100 – 1,300 MM and $300 – 500 MM, respectively

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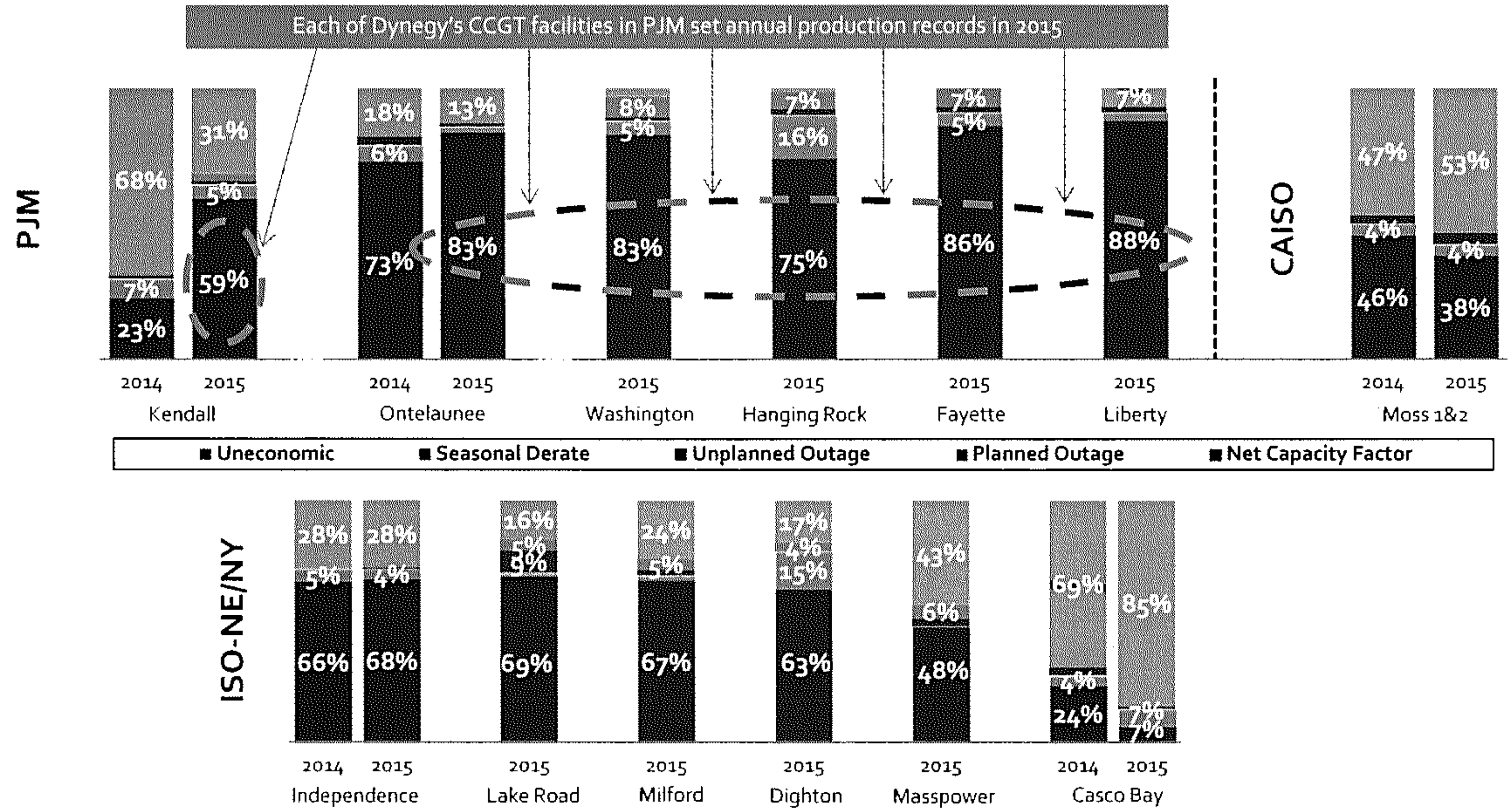
[1] Acquired asset results included from acquisition date forward. Note: Adjusted EBITDA and Free Cash Flow are non-GAAP measures; reconciliations to GAAP can be found in the Appendix

2015 Fleet Performance – Gas Segment

Net Capacity Factors[1]



Exceptional reliability and unrivaled access to low cost gas led to record run-times and strong Gas Segment financial performance

[1] Net Capacity Factor is based on the NERC method of calculation, which uses a maximum capacity rating

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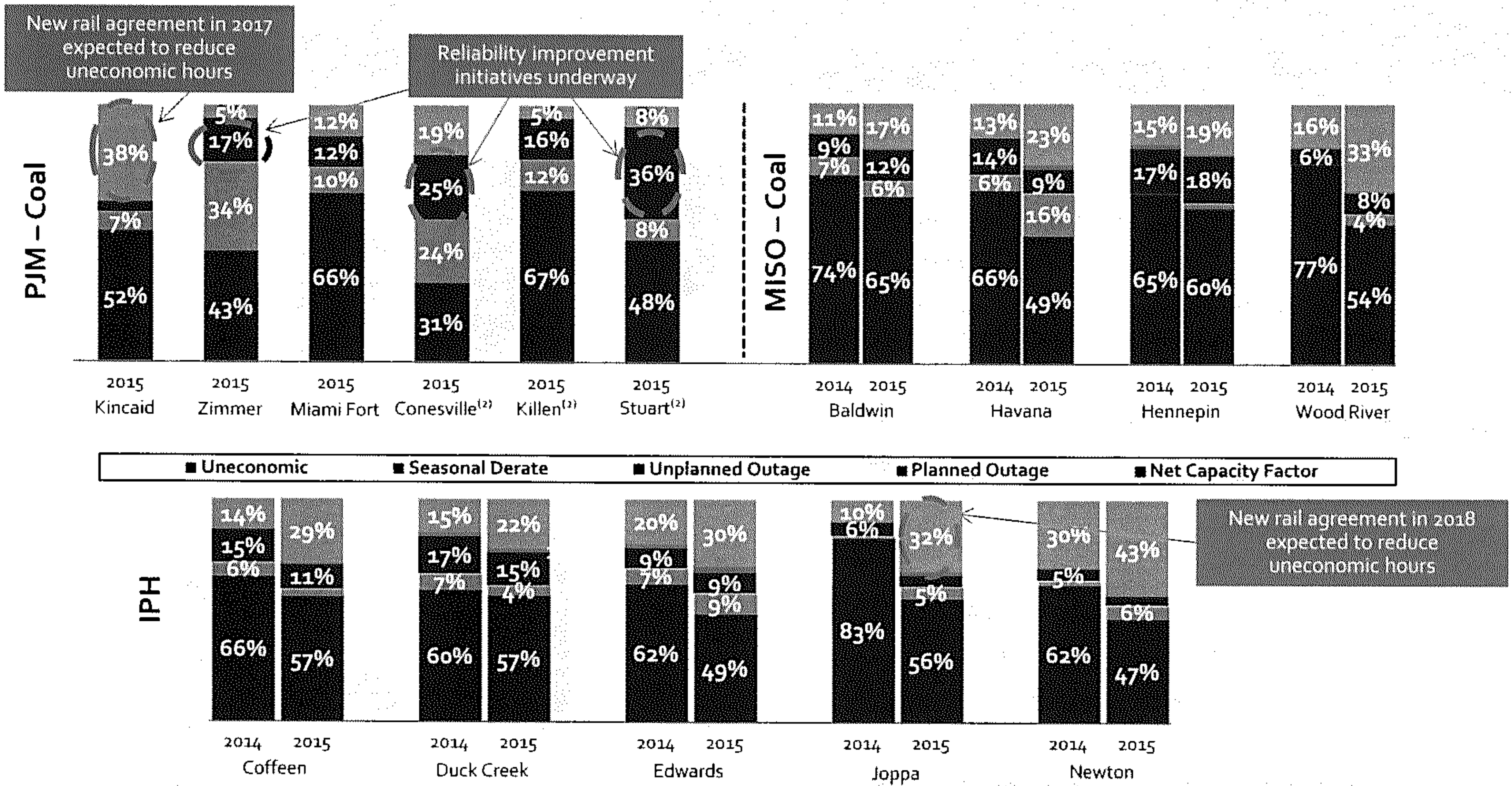
2015 Fleet Performance – Coal & IPH Segments

Net Capacity Factors[1]



A focus on reliability and cost reduction expected to improve capacity factors and reduce uneconomic hours

[1] Net Capacity Factor is based on the NERC method of calculation, which uses a maximum capacity rating; [2] Jointly owned facilities not operated by Dynegy

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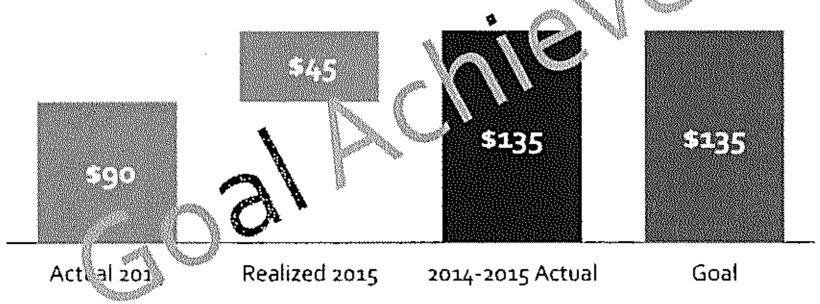
PRIDE Accelerated (2014 – 2015)

Producing Results through Innovation by Dynegy Employees

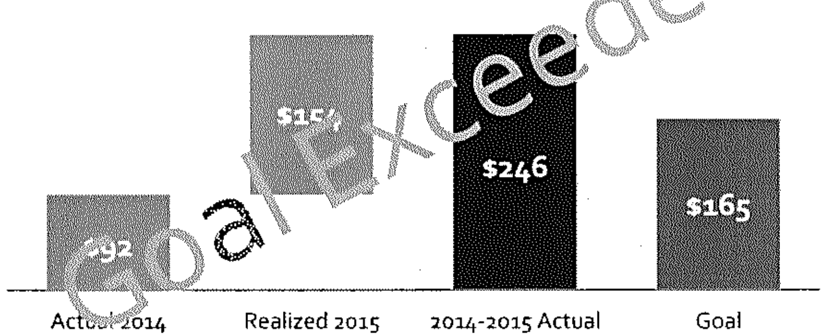
2014-2015 Cumulative EBITDA Improvement Targets and Progress (in $ MM)



EBITDA Initiatives Completed in 2015

- Baldwin transformer upgrade
- Refined coal at MISO Coal Segment
- Gas plant performance improvements
- Optimized emissions control chemical feeds

2014-2015 Cumulative Balance Sheet Efficiency Targets and Progress (in $ MM)



PRIDE Accelerated Balance Sheet Goals Exceeded

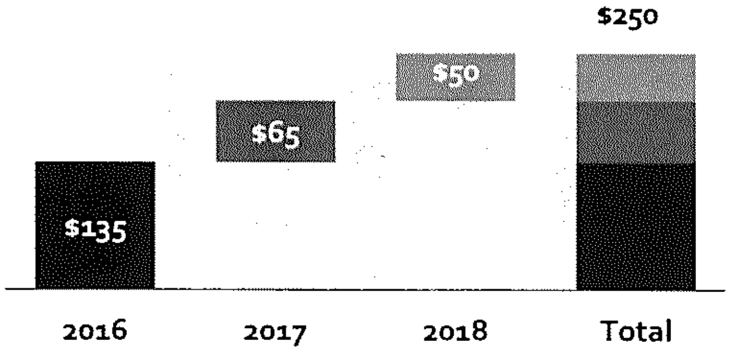
- Collateral program enhancements at IPH
- Continued movement from cash collateral postings to credit sources such as first lien agreements
- Emission credit monetization
- Ponderosa Pine legal settlement

Goals achieved or exceeded one year ahead of schedule

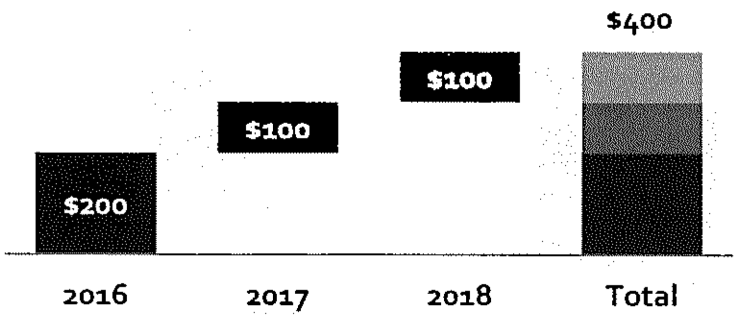
Note: Excludes synergies from Duke Midwest and ECP transactions

PRIDE Energized (2016 – 2018)

2016 – 2018 PRIDE Energized EBITDA (in $ MM)

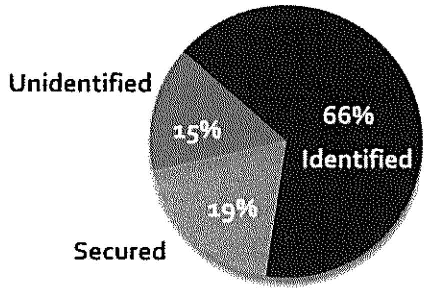


2016 – 2018 PRIDE Energized Balance Sheet (in $ MM)



2016 PRIDE EBITDA Initiatives

Goal of $135 MM

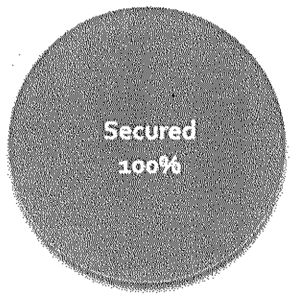


Initiatives

- NE/NY gas transport optimization
- MISO congestion relief
- Supply chain
- Legacy gas plant uprates

2016 PRIDE Balance Sheet Initiatives

Goal of $200 MM



Balance Sheet Initiatives

- Collateral program improvements
- Return of previously posted credit support

PRIDE Energized built from the success of prior PRIDE programs

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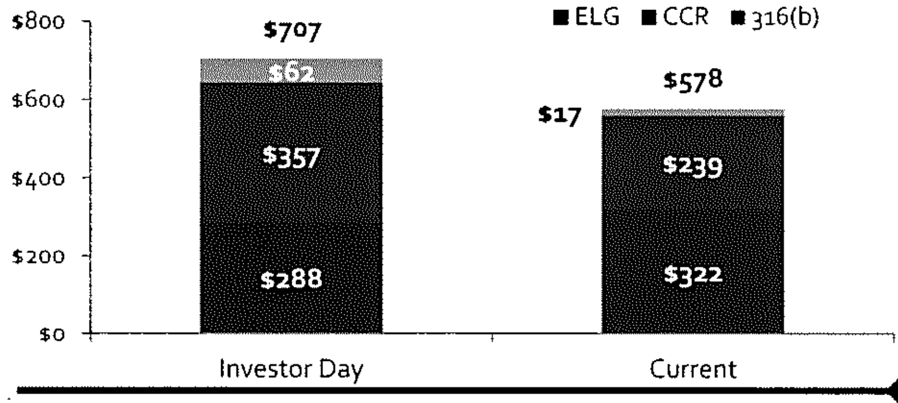
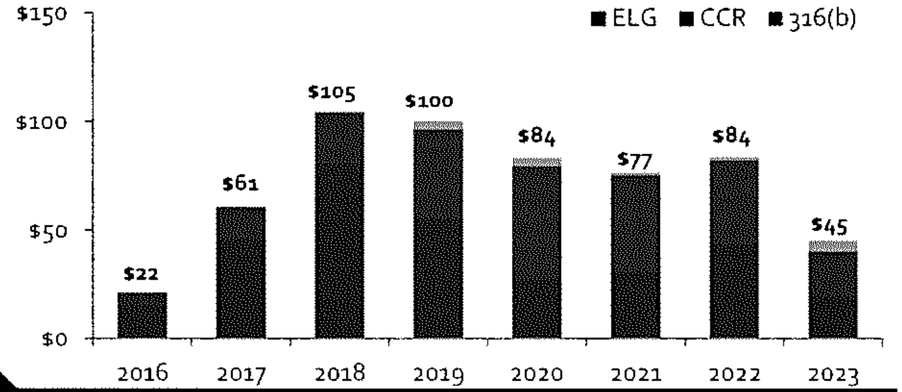
Environmental Compliance Spend Update

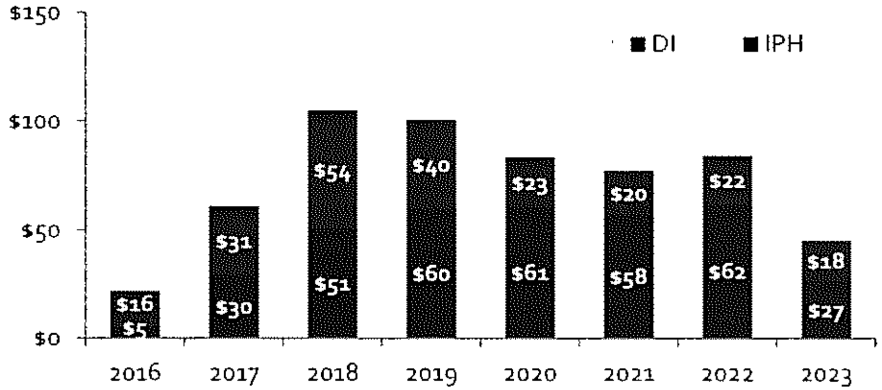
Total Spend Comparison: Investor Day vs. Current (~$ MM)



Expected Cash Cost for Major Environmental Rules (~$ MM)



Spend Breakout: IPH vs. DI (~$ MM)



- ELG final ruling implements stricter guidelines to include units greater than 50 MW versus original 400 MW estimate
  - ELG spend increased by $34 MM to include Hennepin, Joppa and Edwards
  - Potential reduction at Baldwin pending ground water test results
- 316(b) cost estimates decreased by $45 MM primarily due to final rule classification of cooling lakes as closed loop systems ($22 MM) and later spend profile beyond 2023 ($9 MM)
- ~95% of CCR spend accrued on the balance sheet as part of Dynegy's ARO obligation

Cost estimates have declined despite stricter guidelines

Note: Total compliance spend for 2016-2023

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Commercial Overview

Hank Jones, Chief Commercial Officer

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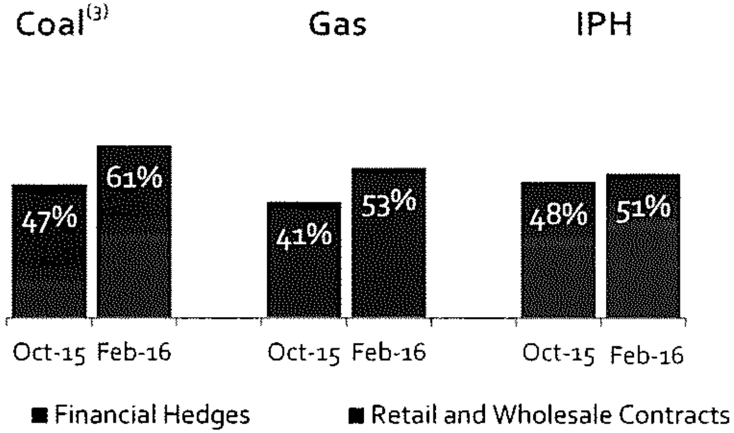
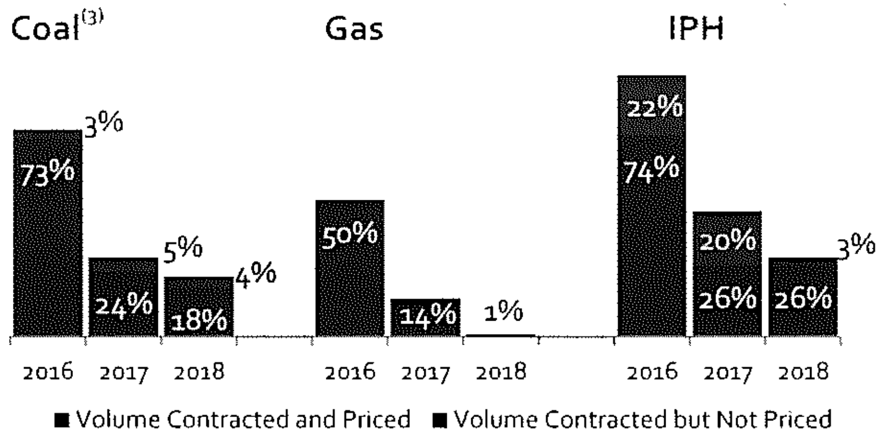
Commercial Update

2016 Generation Volumes Hedged by Segment[1]



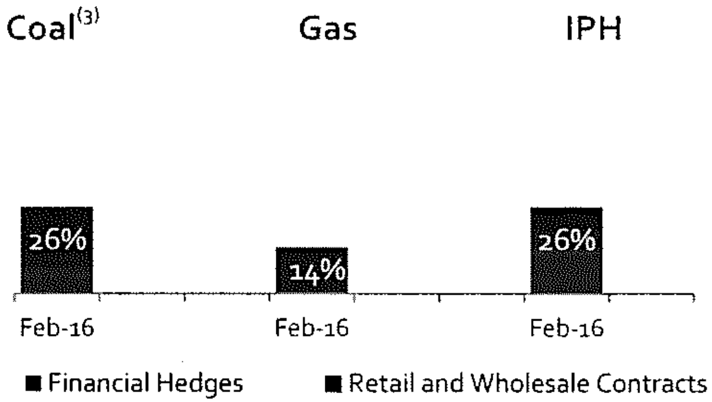
Fuel Supply Hedged[2]



Contracted Rail and Barge Transportation

	2016	**2017**	**2018-2020**
Coal segment	100%	99%	67%
IPH	100%	100%	58%

2017 Generation Volumes Hedged by Segment[2]



- 2016 Gas Segment hedges lock in attractive spark spreads and remaining open position provides protection against declining gas prices
- Gas Segment hedges concentrated in PJM, New York and New England
- IPH hedge activity driven by retail sales
- 2016 on-peak Coal Segment ~65% hedged

(1) As of 10/19/2015 and 2/8/2016; (2) As of 2/8/2016; (3) Excludes Brayton Point & Wood River

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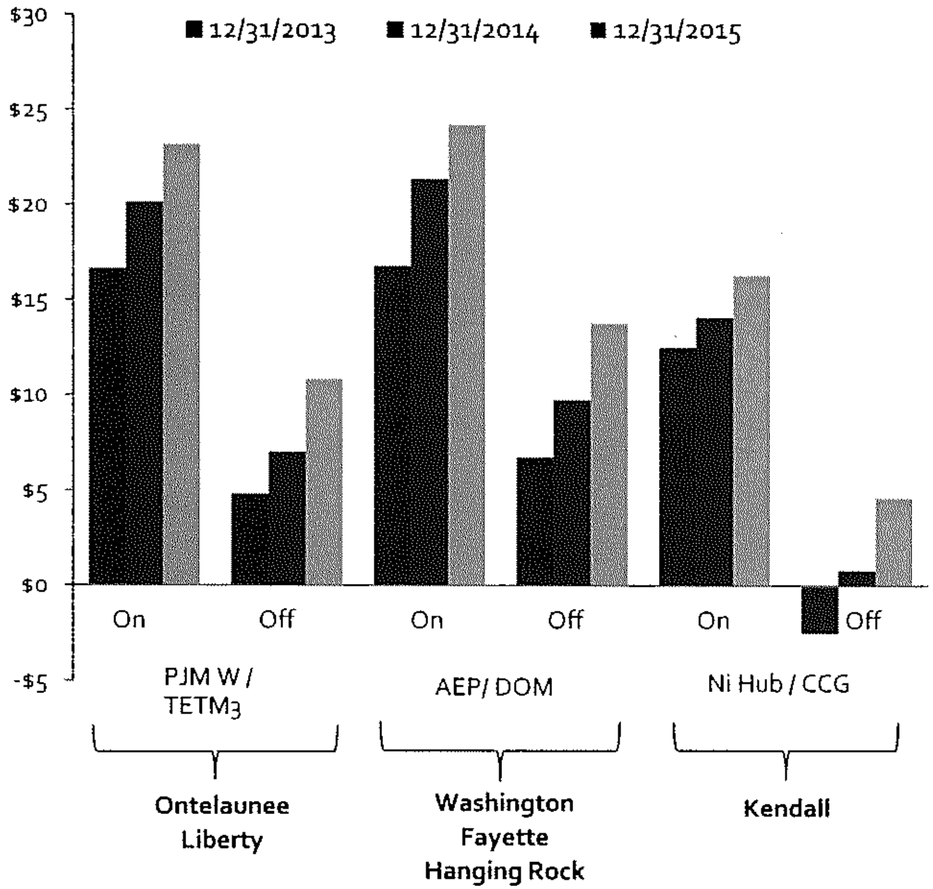
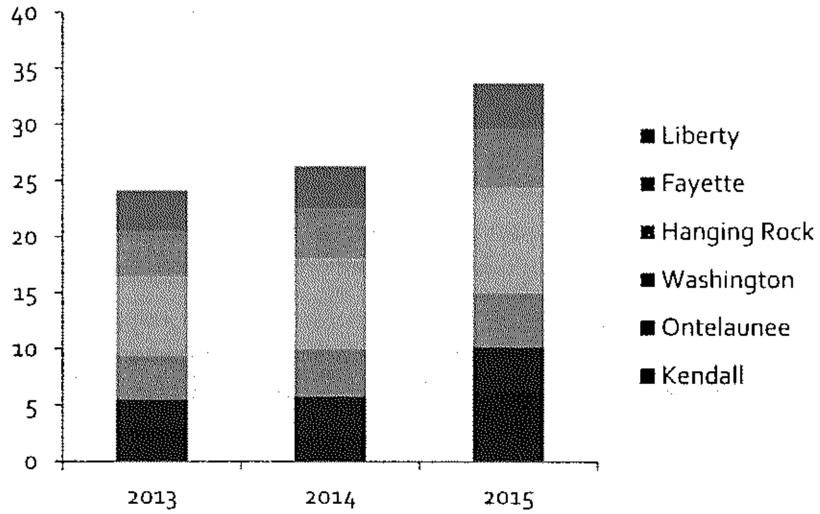
PJM Market Developments

2017 Spark Spreads ($/MWh)



Generation Volumes (MM MWh)



Other PJM Highlights

- Forward spark spreads have steadily improved
- Record generation levels set at PJM CCGTs in 2015
- Significant fuel cost advantage for Dynegy's PJM CCGT fleet has resulted in those plants running as baseload

Unrivaled access to low cost fuel and strong reliability performance driving higher spark spreads and record generation levels

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MISO Market Developments

Dynegy Capacity in the 2016/2017 Planning Year

	~MWs	Price ($/MW-day)	~Revenue (in $MM)
MISO UCAP[1]	6,100		
Exports to PJM - CP	730	$134.00	$35
Exports to PJM - Base	137	$59.37	$3
Bilateral Sales[2]	913		
Wholesale Sales[2]	460	$125.61	$140
Retail Sales[2]	1,680		
Sold to Date	3,920		**$178**
Uncommitted Capacity	2,180		

2016/2017 Capacity Summary

- $178 MM in capacity revenues locked in for PY 16/17 vs. $105 MM for prior PY 15/16
- ~35% of MISO PY 16/17 capacity available for sale
- UCAP number reflects retirement of Wood River and addition of Joppa CTs
- Every $10/MW-day of Uncommitted Capacity sold = $8 MM in additional capacity revenues
- Secured a three year PY 16/17 – PY 18/19, 959 MW Retail sale

Other MISO Highlights

- Wood River retirement notice filed on November 24, 2015
- Effective June 1, 2016, 22% of the IPH fleet becomes dedicated PJM resource via pseudo ties
- Dynegy working closely with MISO task team on Zone 4 market redesign

Proactively pursuing multiple channels to market

[1] UCAP represents MWs that qualify as capacity available to be sold in MISO after reflecting an historical outage rate; [2] Customer obligation supply and load either matched outside of the MISO capacity auction or self-scheduled within the annual capacity auction

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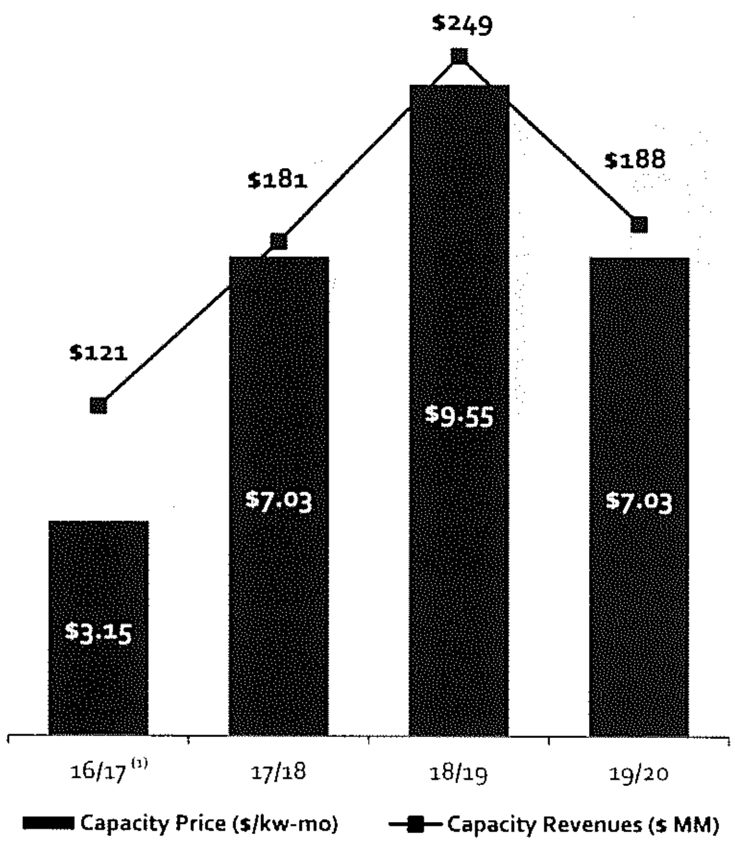
ISO-NE Market Developments

Capacity Auction Results by Planning Year



Auction Highlights

- PY 19/20 auction cleared at $7.03/kW-month ($235/MW-day) resulting in revenues of $188 MM
- Dynegy's 70 MW of ISO-NE uprates qualified for a seven year rate-lock of $7.03/kW-month beginning in PY 19/20
- Uprates projected to cost $26 MM in total will generate $41 MM in capacity revenues over the seven year rate-lock period
- 1.4 GW of new capacity cleared PY 19/20 auction

Other ISO-NE Highlights

- 4-5 GW of older units remain at risk
- Secured a one year tolling agreement for 2016 at Casco Bay (538 MW)[2]
- Secured a three year 75 MW bilateral capacity contract at $7.50/kW-month for PY 19/20 through PY 21/22

Capacity revenue growth and uprates lock-in strong cash flows

(1) Includes $49 MM for Brayton Point
(2) Winter capacity rating

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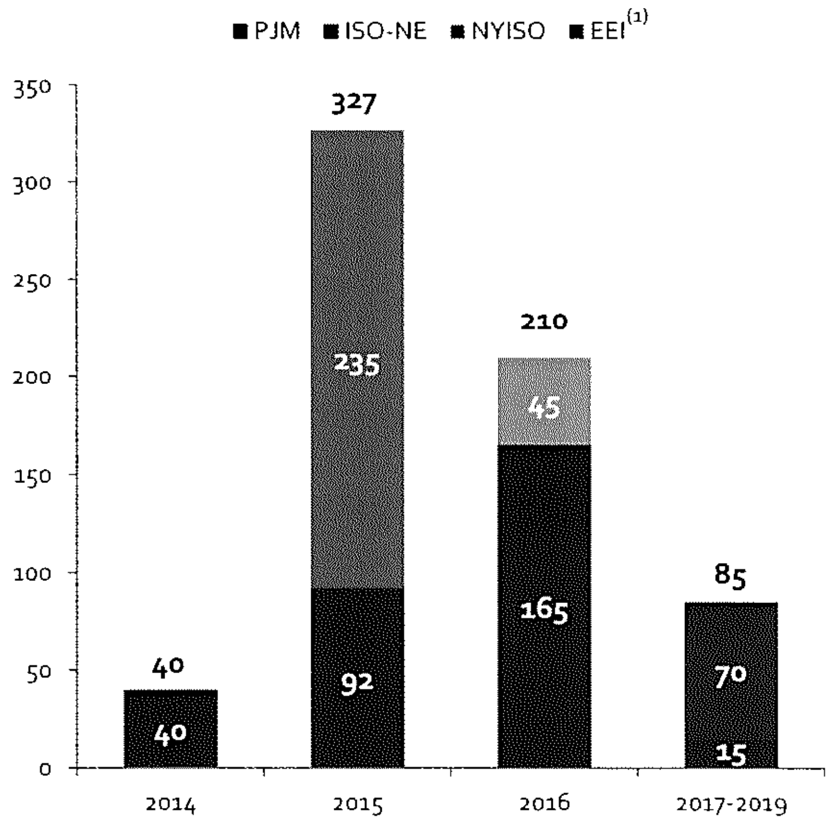
Low Cost Expansions With Quick Paybacks

Capacity Uprates by Year (MW)



Uprate Summary

- Over 650 MW of uprates scheduled to occur by 2019
- IRRs in the high double-digits with an abbreviated payback period
- 70 MW of uprates at ISO-NE qualified for a 7-year rate lock in FCA-10
- Hanging Rock uprates expected to be 60 MW, produced 72 MW plus an additional 20 MW of peak firing
- Brought 235 MW of previously mothballed MISO CTs back online in 2015
- Projected average cost of uprates:
    - PJM projects ~$270/kW
    - ISO-NE projects ~$310/kW
    - EEI CTs ~$5/kW

Uprates at prices well below new build economics and recent market transactions

(1) EEI can sell into TVA, KU, or MISO

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Commercial Summary

- Hedging to protect cash flow while preserving upside potential
- PJM CCGT fleet setting production records
- $178 MM in MISO capacity revenue locked in for PY 16/17 with ~2,200 MW available for sale
- ISO-NE to generate ~$750 MM in capacity revenues over the next four planning years

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2015 Full Year and Fourth Quarter Financial Results

Clint C. Freeland, CFO

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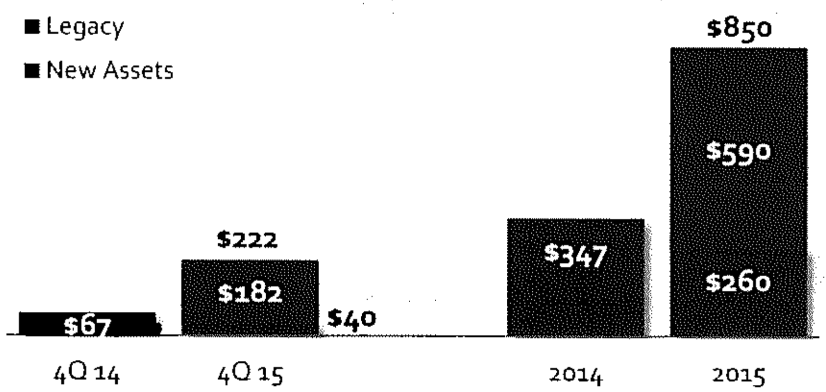
Financial Summary

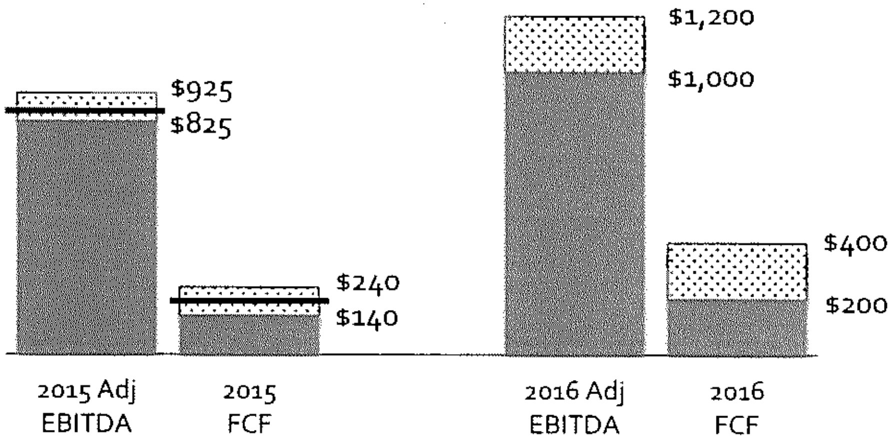
Adjusted EBITDA Results[1] ($ MM)



Liquidity as of 12/31/2015[2] ($ MM)

Unrestricted Cash at Dynegy Inc.	$443
Revolver Capacity at Dynegy Inc.	$1,005
Total Dynegy Inc. Liquidity (excluding IPH)	**$1,448**
Unrestricted Cash at IPH	$62
Revolver Capacity at IPH	$3
Total IPH Liquidity	**$65**

Guidance ($ MM)



Financial Summary Update

- Continued strong contributions from the recently acquired assets
- Achieved 2015 Adjusted EBITDA and Free Cash Flow targets even in a low commodity environment
- 2016 Guidance ranges updated due to declines in expected gross margin

[1] Corporate overhead included in legacy Adjusted EBITDA; [2] See Appendix for additional detail. Note: Adjusted EBITDA and Free Cash Flow are non-GAAP measures; reconciliations to GAAP can be found in the Appendix

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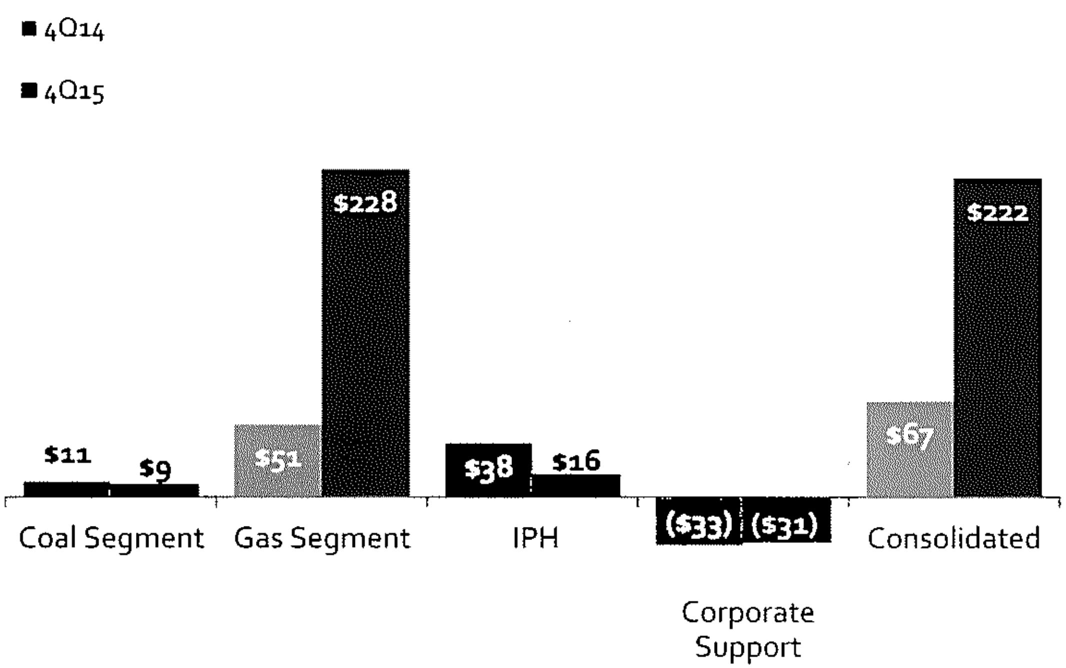
Fourth Quarter Period-over-Period Segment Performance

4Q Period-over-Period Adjusted EBITDA ($ MM)



Coal Segment	
New Assets	$17 MM
Energy Margin	($8) MM
Wholesale Capacity	$4 MM
Planned Outages (O&M)	($12) MM
Retail and Other O&M	($8) MM
Gas Segment	
New Assets	$165 MM
Independence Contract	($11) MM
Energy Margin	$14 MM
Wholesale Capacity	$8 MM
IPH	
Wholesale Capacity	$26 MM
Non-recurring Retail Adjustment	($16) MM
Energy Margin	($28) MM
O&M	($6) MM

New assets and higher capacity revenues benefit quarterly results

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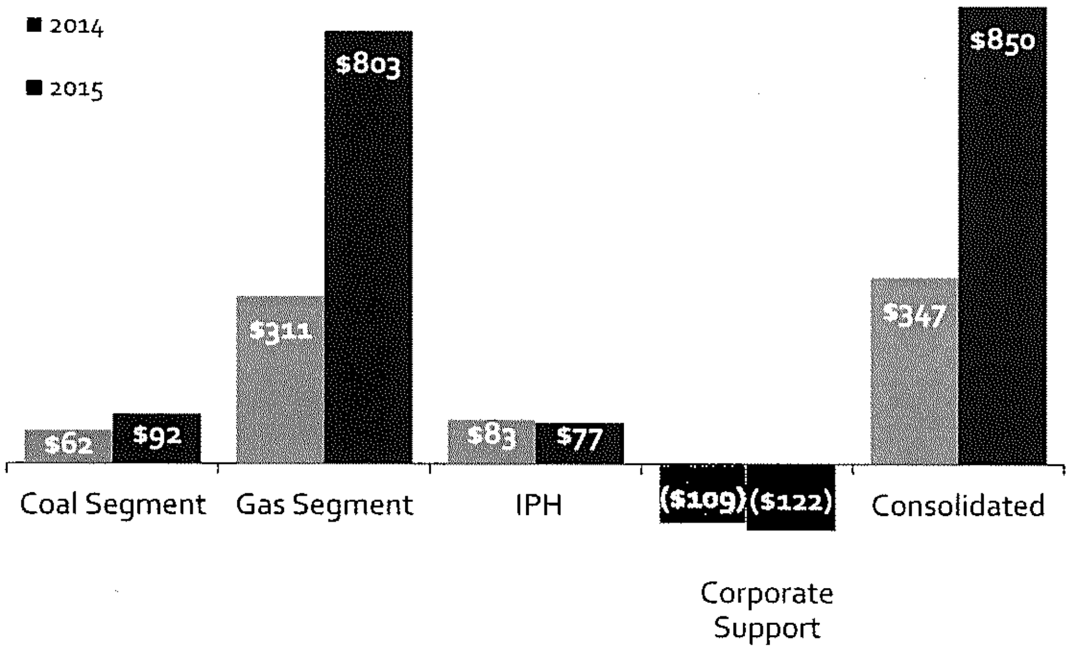
Full Year Period-over-Period Segment Performance

Full Year Period-over-Period Adjusted EBITDA ($ MM)



Coal Segment	
New Assets	$79 MM
Energy Margin	($38) MM
Wholesale Capacity	$11 MM
Planned Outages (O&M)	($15) MM
Other O&M	($14) MM
Gas Segment	
New Assets	$511 MM
Independence Contract	($97) MM
Energy Margin	$23 MM
Wholesale Capacity	$47 MM
O&M	$12 MM
IPH	
Energy Margin	($85) MM
Wholesale Capacity	$82 MM
O&M	($11) MM

Increase in results primarily driven by the addition of new assets

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2015 Full Year Free Cash Flow

(in $ MM)	Dynegy Inc.	IPH[1]	Consolidated
Adjusted EBITDA	$773	$77	$850
Cash Interest	($366)	($59)	($425)
Working Capital/Other	($14)	$2	($12)
Capital Spending	($175)	($52)	($227)
Free Cash Flow	$218	($32)	$186

Adjusted EBITDA

- New Assets contributed $590 MM of Adjusted EBITDA
- $140 MM increase in capacity revenue with majority of uplift at IPH

Cash Interest

- Cash interest on acquisition debt only included for post-close period after April 1, 2015

Capital Spending

- Capital spending comprised of $199 MM in maintenance and $28 MM in environmental
  - Lower than expected capital spend due to outage savings at MISO coal fleet
  - Includes ~$18 MM of environmental spend for Newton Scrubber
- Capital spending excludes $56 MM in discretionary growth projects such as:
  - Baldwin transformer upgrade ($7)
  - Acquisition of Berks Hollow ($18)
  - Uprate projects ($31)

Well positioned gas fleet provides strong cash flow in low cost gas environment

[1] Segment results before the allocation of Corporate G&A expense; Note: Adjusted EBITDA and Free Cash Flow are non-GAAP measures; reconciliations to GAAP can be found in the Appendix

Updated 2016 Adjusted EBITDA and Free Cash Flow Guidance

Consolidated Dynegy Inc. ($ MM)

	Updated	Initial[1]
Adjusted EBITDA	$1,000 - 1,200	$1,100 - 1,300
Maintenance CapEx	($300)	($300)
Recurring Environmental CapEx	($20)	($20)
Cash Interest	($515)	($515)
Other Cash Impacts	$35	$35
Free Cash Flow	$200 - 400	$300 - 500

Guidance Update

- Around-the-clock power prices for FY 2016 have declined since the initial guidance date:
  - Indy Hub down $4.47 or 15%
  - AD Hub down $3.73 or 11%
  - Mass Hub down $39.36 or 51% for Jan/Feb
- Many key around-the-clock spark spreads have declined since the initial guidance date:
  - NY Gas (Zone A/Dominion) down $2.42 or 12%
  - NE Gas (Mass Hub/Algonquin) down $1.88 or 15%
- PJM around-the-clock spark spreads have remained fairly stable overall
- Forecast excludes Wood River
- IPH Adjusted EBITDA, before G&A allocations, now estimated at ~$100 MM
- Capital Allocation
  - DI: $30 MM in Mandatory Converts/Term Loan Amortization & $35 MM in gas plant uprates
  - IPH: $50 MM in non-recurring environmental

[1] As presented November 4, 2015 Note: Adjusted EBITDA and Free Cash Flow are non-GAAP measures; reconciliations to GAAP can be found in the Appendix

Summary

Robert C. Flexon, President and CEO

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Key Takeaways

Acquired assets significantly strengthened the Company's portfolio

Growing spark spreads leading to production records of Dynegy's PJM CCGT facilities

ISO-NE provides higher capacity price clears while MISO capacity becoming increasingly valuable

Guidance update reflects price impact of moderate weather

Appendix

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Dynegy Generation Facilities

Portfolio/Facility[1]	*Location*	*Net Capacity[2]*	*Primary Fuel*	*Dispatch Type*	*Market Region*
Coal Segment					
Baldwin	Baldwin, IL	1,815	Coal	Baseload	MISO
Havana[3]	Havana, IL	434	Coal	Baseload	MISO
Hennepin	Hennepin, IL	294	Coal	Baseload	MISO
Wood River	Alton, IL	465	Coal	Baseload	MISO
Stuart*	Aberdeen, OH	904	Coal	Baseload	PJM
Miami Fort 7&8*	North Bend, OH	653	Coal	Baseload	PJM
Miami Fort CT	North Bend, OH	75	Oil – CT	Peaking	PJM
Zimmer*	Moscow, OH	628	Coal	Baseload	PJM
Conesville*	Conesville, OH	312	Coal	Baseload	PJM
Killen*	Manchester, OH	204	Coal	Baseload	PJM
Kincaid	Kincaid, IL	1,108	Coal	Baseload	PJM
Brayton Point	Somerset, MA	1,528	Coal	Baseload	ISO-NE
Coal Segment TOTAL		**8,420**			
IPH					
Coffeen	Coffeen, IL	915	Coal	Baseload	MISO
Joppa*[4]	Joppa, IL	802	Coal	Baseload	MISO
Joppa CT 1-3[4]	Joppa, IL	165	Gas – CT	Peaking	MISO
Joppa CT 4-5*[4]	Joppa, IL	56	Gas – CT	Peaking	MISO
Newton	Newton, IL	1,230	Coal	Baseload	MISO
Duck Creek	Canton, IL	425	Coal	Baseload	MISO
E.D. Edwards	Bartonville, IL	585	Coal	Baseload	MISO
IPH TOTAL		**4,178**			

NOTES:

1) Dynegy owns 100% of each unit listed except for those marked by an asterisk (*). Total Net Capacity set forth in this table for partially owned units includes only Dynegy's proportionate share of that facility's gross generating capacity.
2) Unit capabilities are based on winter capacity ratings.
3) Represents Unit 6 generating capacity.
4) Not located within MISO.

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Dynegy Generation Facilities, cont.

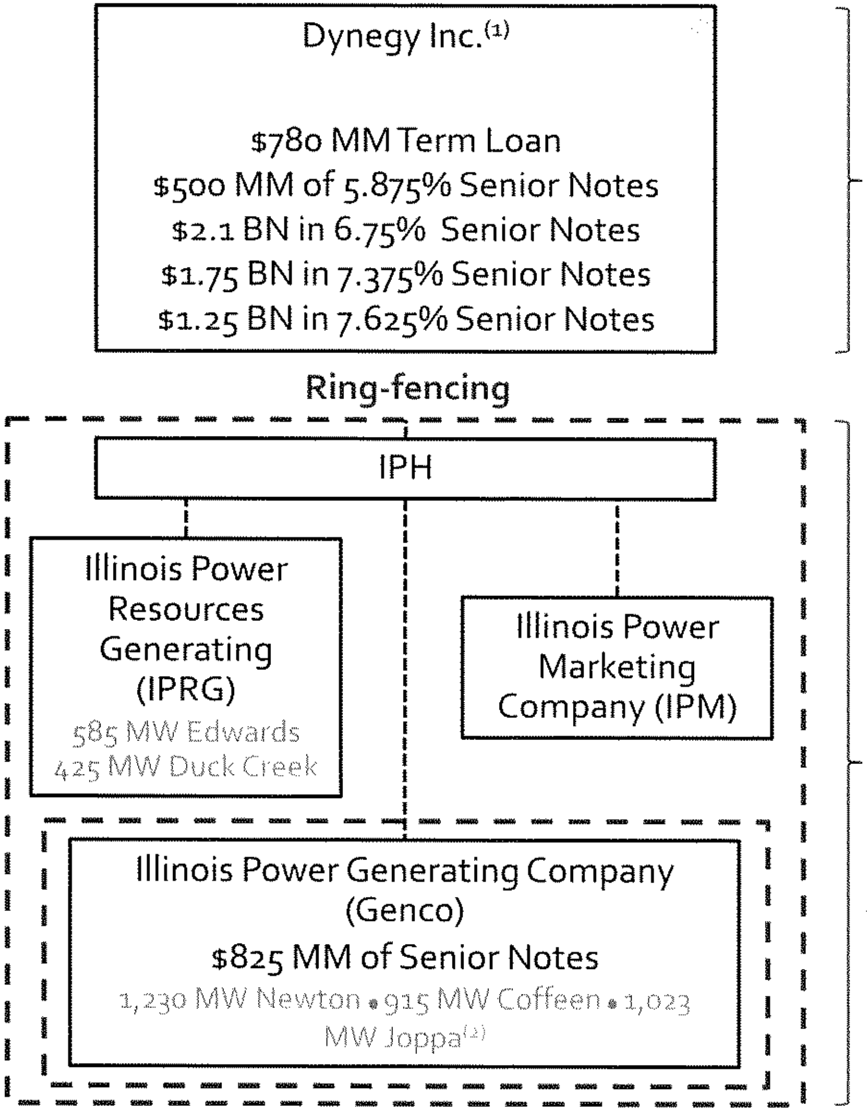
Portfolio/Facility[1]	Location	Net Capacity[2]	Primary Fuel	Dispatch Type	Market Region
Gas Segment					
Casco Bay	Veazie, ME	538	Gas – CCGT	Intermediate	ISO-NE
Milford	Milford, CT	569	Gas – CCGT	Intermediate	ISO-NE
Lake Road	Dayville, CT	857	Gas – CCGT	Intermediate	ISO-NE
Dighton	Dighton, MA	185	Gas – CCGT	Intermediate	ISO-NE
Masspower	Indian Orchard, MA	280	Gas – CCGT	Intermediate	ISO-NE
Independence	Oswego, NY	1,126	Gas – CCGT	Intermediate	NYISO
Kendall	Minooka, IL	1,236	Gas – CCGT	Intermediate	PJM
Ontelaunee	Reading, PA	567	Gas – CCGT	Intermediate	PJM
Hanging Rock	Ironton, OH	1,439	Gas – CCGT	Intermediate	PJM
Washington	Beverly, OH	678	Gas – CCGT	Intermediate	PJM
Fayette	Masontown, PA	696	Gas – CCGT	Intermediate	PJM
Liberty	Eddystone, PA	598	Gas – CCGT	Intermediate	PJM
Dicks Creek	Monroe, OH	143	Gas – CT	Peaking	PJM
Lee	Dixon, IL	757	Gas – CT	Peaking	PJM
Elwood*	Elwood, IL	788	Gas – CT	Peaking	PJM
Richland	Defiance, OH	418	Gas – CT	Peaking	PJM
Stryker	Stryker, OH	17	Oil – CT	Peaking	PJM
Moss Landing	Moss Landing, CA				
Units 1-2		1,020	Gas – CCGT	Intermediate	CAISO
Units 6-7		1,509	Gas – CT	Peaking	CAISO
Oakland	Oakland, CA	165	Oil – CT	Peaking	CAISO
Gas Segment TOTAL		**13,586**			
TOTAL GENERATION		**26,184**			

NOTES:

1) Dynegy owns 100% of each unit listed except for those marked by an asterisk (*). Total Net Capacity set forth in this table for partially owned units includes only Dynegy's proportionate share of that facility's gross generating capacity.
2) Unit capabilities are based on winter capacity ratings.
3) Represents Unit 6 generating capacity.
4) Not located within MISO.

DYNEGY

Debt, Liquidity, and Ring-fencing (as of 12/31/2015)



Available Liquidity ($ MM)

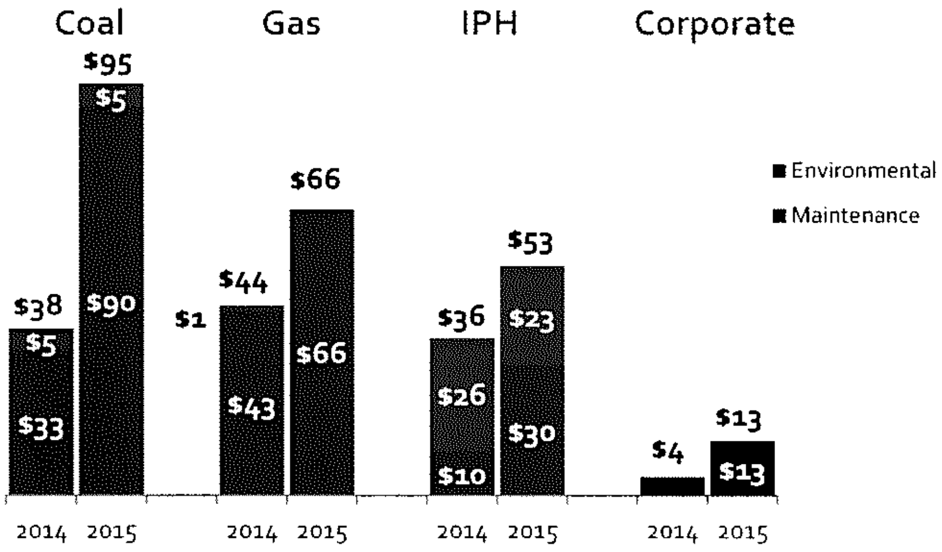
Cash and Equivalents	$443
Revolver Capacity	*$1,480*
Outstanding LCs	*($475)*
Revolver Availability	$1,005
Total DI Liquidity	**$1,448**
Cash and Equivalents[3]	$62
Revolver Capacity	*$48*
Outstanding LCs	*($45)*
Revolver Availability	$3
Total IPH Liquidity	**$65**

[1] Excludes $80MM of nonrecourse Elwood Senior Notes; [2] Reflects 80% stake; [3] GenCo cash of $61 million

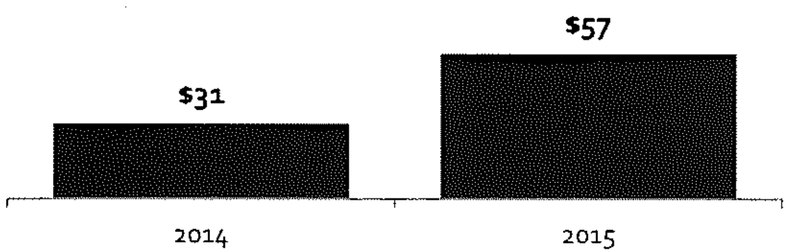
DYNEGY

Capital and Major Maintenance O&M Expenditures Year-Over-Year

Capital Expenditures by Segment[1][2] ($ MM)



Total Major Maintenance Expense ($ MM)



[1] Excludes capitalized interest; [2] Excludes discretionary investments for growth and reliability

Coal Segment

- Maintenance capital spending increased due to the addition of the Duke Midwest and ECP fleets
- Maintenance capital spending increased primarily due to outage at Havana

Gas Segment

- Maintenance capital spending increased primarily due to the addition of the Duke Midwest and ECP fleets

IPH

- Maintenance capital spending increased due to outage work at Edwards and Joppa

Corporate

- Maintenance capital spending increased primarily due to office HQ expansion

Coal, Gas, and IPH Segments

- Increase in maintenance expense mostly due to the addition of the Duke Midwest and ECP fleets

DYNEGY

Operational Statistics

Coal Segment[1]	4Q14	4Q15	2014	2015
Total Generation (MM MWh)				
MISO	4.6	3.0	19.0	15.9
PJM	N/A	4.1	N/A	12.5
Brayton Point	N/A	0.5	N/A	0.9
In-Market-Availability				
MISO	88.1%	86.7%	87.9%	87.2%
PJM	N/A	77.5%	N/A	74.3%
Brayton Point	N/A	93.3%	N/A	91.9%
Average Capacity Factor[2]				
MISO	69.2%	45.2%	72.8%	60.5%
PJM	N/A	49.0%	N/A	50.9%
Brayton Point	N/A	15.5%	N/A	8.9%

IPH[1]	4Q14	4Q15	2014	2015
Total Generation (MM MWh)	5.9	3.8	23.7	18.5
In-Market-Availability	86.6%	85.7%	88.9%	88.6%
Average Capacity Factor[2]	66.6%	42.8%	68.2%	52.2%

[1] In-Market Availability and Average Capacity Factor do not include CTs; [2] Average Capacity Factor is based on the NERC method of calculation, which uses a maximum capacity rating

DYNEGY

Operational Statistics, cont.

Gas Segment - Combined Cycle	4Q14	4Q15	2014	2015
Total Generation (MM MWh)				
California	0.8	1.0	4.0	3.4
NY/NE	1.6	4.1	7.1	14.8
PJM	1.6	8.3	5.8	27.7
In-Market-Availability				
California	98.9%	97.4%	98.4%	96.3%
NY/NE	100%	98.6%	99.7%	97.8%
PJM	96.7%	98.1%	97.9%	98.7%
Average Capacity Factor[1]				
California	37.1%	43.5%	45.6%	38.4%
NY/NE	46.2%	53.2%	52.1%	55.7%
PJM	42.8%	74.3%	38.9%	74.9%

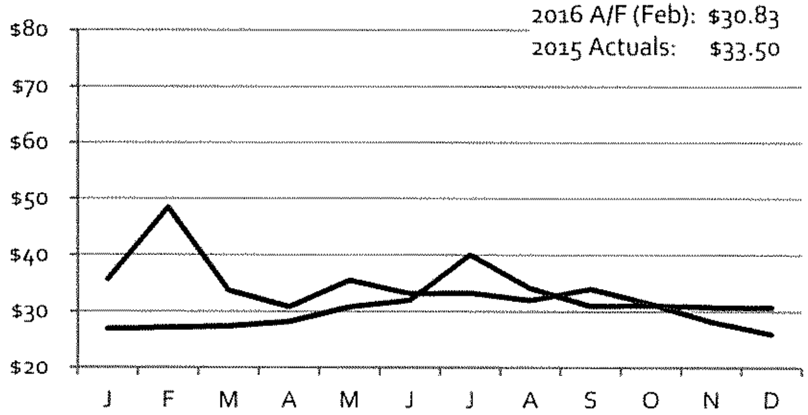
[1] Average Capacity Factor is based on the NERC method of calculation, which uses a maximum capacity rating

DYNEGY

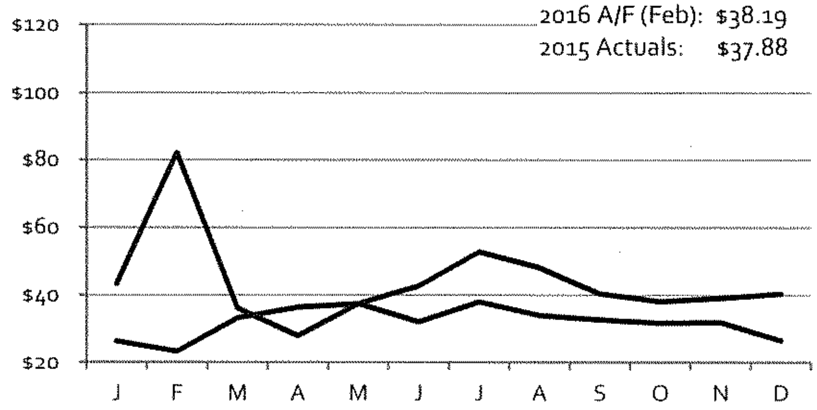
Commodity Pricing (on-peak power)

2015 Actuals 2016(1)

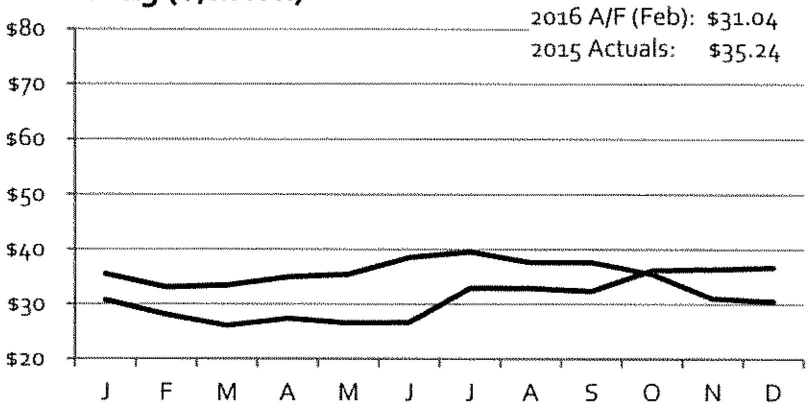
Indiana Hub ($/MWh)



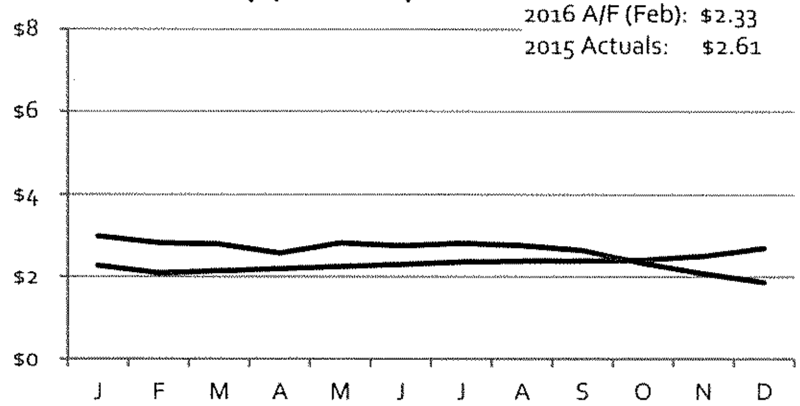
New York Zone A ($/MWh)



NP-15 ($/MWh)



Natural Gas ($/MMBtu)



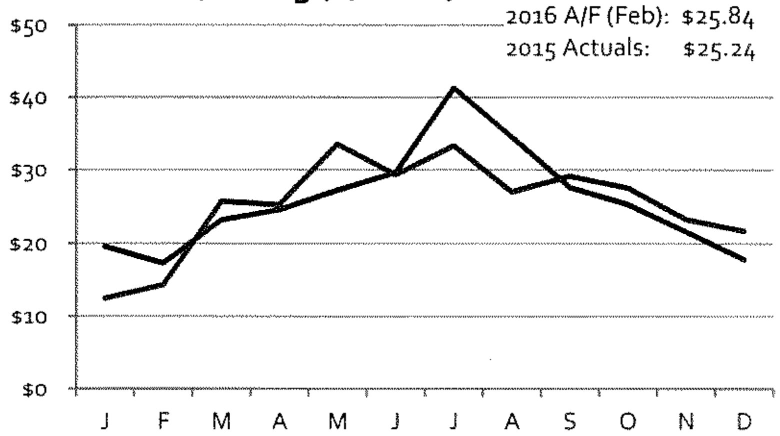
(1) 2016 Prices reflect actual day ahead on-peak settlement prices for 1/1/2016-2/8/2016 and quoted forward on-peak monthly prices for 2/9/2016-12/31/2016

DYNEGY

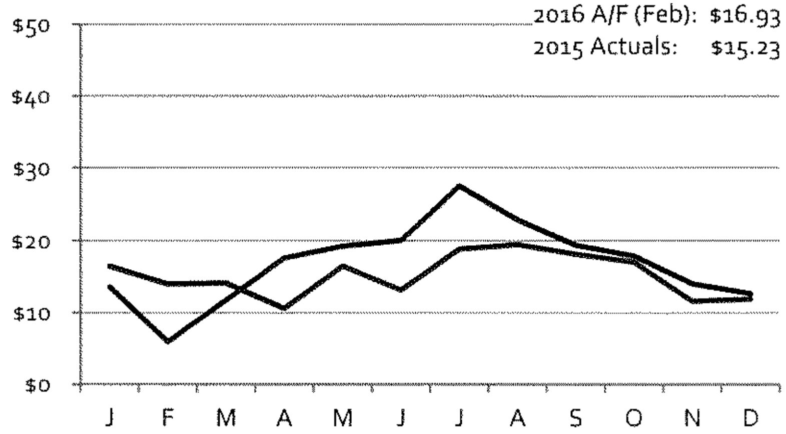
Spark Spreads (on-peak)

2015 Actuals　2016[1]

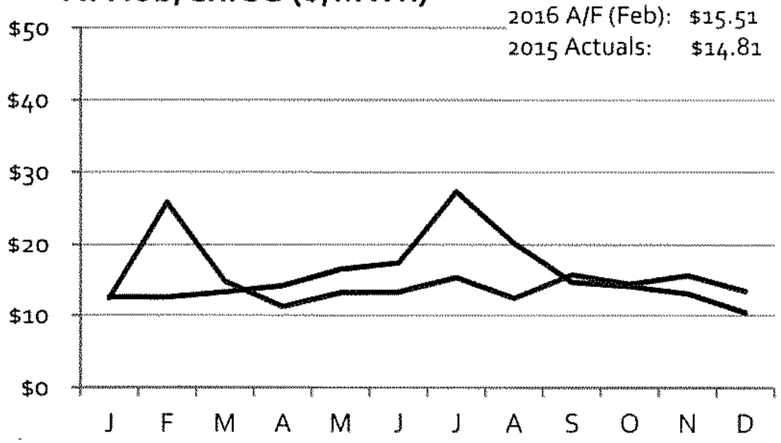
PJM West/TetM3 ($/MWh)



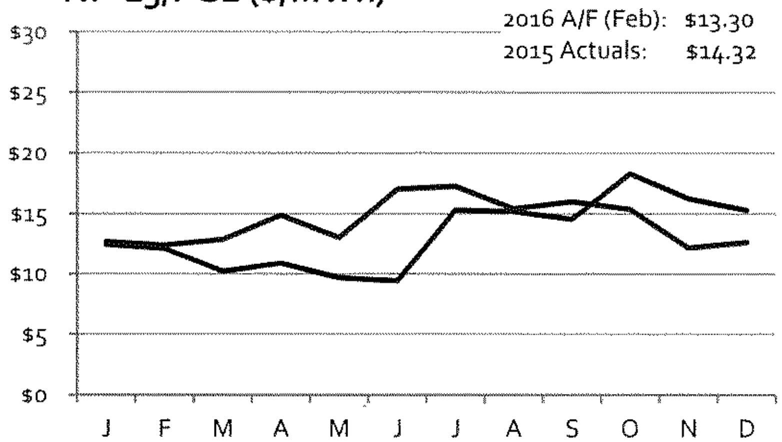
Mass Hub/Algonquin ($/MWh)



NI Hub/ChiCG ($/MWh)



NP-15/PGE ($/MWh)



[1] 2016 Prices reflect actual day ahead on-peak settlement prices for 1/1/2016-2/8/2016 and quoted forward on-peak monthly prices for 2/9/2016-12/31/2016

DYNEGY

Market Pricing

Average Actual Power/Gas Prices ($/MWh)

	4Q14		4Q15		2014		2015	
	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Henry Hub ($/MMBtu)	$3.75		$2.09		$4.34		$2.61	
Indy Hub	$38.54	$29.06	$28.52	$22.00	$48.28	$32.52	$33.50	$24.56
Mass Hub	$48.39	$34.57	$34.98	$22.81	$76.97	$54.58	$48.96	$34.88
NP-15	$46.44	$37.40	$32.33	$27.40	$51.15	$41.26	$35.23	$28.84
NY - Zone A	$38.02	$25.79	$30.12	$13.16	$57.55	$37.00	$37.88	$22.11
PJM-W	$42.20	$30.74	$33.02	$24.03	$62.71	$40.86	$43.21	$29.81
AD Hub	$41.56	$30.07	$31.29	$23.32	$54.86	$34.81	$37.52	$26.40
NiHub	$37.55	$26.27	$29.60	$20.68	$50.60	$30.74	$33.98	$22.79

Average Trading Hub Spark Spreads ($/MWh)

	4Q14		4Q15		2014		2015	
	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
PJM West/TetM3	$23.26	$11.80	$24.20	$15.21	$26.82	$4.97	$25.24	$11.84
NiHub/ChiCG	$10.25	-$1.03	$14.49	$5.57	$11.60	-$8.26	$14.81	$3.62
NP-15/PGE	$17.04	$7.99	$13.39	$8.45	$17.18	$7.30	$14.32	$7.93
NY-Zone A/Dominion	$21.01	$8.77	$21.96	$5.00	$34.64	$14.09	$27.60	$11.84
Mass Hub/Algonquin	$13.35	-$0.48	$13.59	$1.42	$20.08	-$2.31	$15.23	$1.14
AD Hub/Dominion	$24.55	$13.06	$26.24	$15.16	$31.94	$11.89	$28.22	$16.13

DYNEGY

MISO Capacity Channels to Market

Price in $/kw-mo	Coal Segment	IPH	Total	EBITDA Contribution
PY 15/16				
MWs	516	2,922	3,438	
Average Price	$4.00	$2.29	$2.55	$105 MM
PY 16/17				
MWs	913	3,007	3,920	
Average Price	$2.93	$4.06	$3.79	$178 MM
PY 17/18				
MWs	579	2,604	3,183	
Average Price	$2.35	$4.45	$4.07	$155 MM
PY 18/19				
MWs	242	2,352	2,594	
Average Price	$2.68	$4.99	$4.78	$149MM
PY 19/20				
MWs	185	470	655	
Average Price	$2.60	$5.61	$4.76	$37 MM
Total MWs	2,435	11,355	13,790	
Average Price	$2.97	$3.95	$3.78	$624 MM

Capacity Updates for PY 2016/2017

- Additional retail sales in Q4
- Removal of Wood River from Open Position
- Addition of Joppa CT's to Open Position
- Secured 3 year Retail deal 16/17-18/19

Remaining Open Capacity Could Contribute Material EBITDA Increase

- ~14 GW of MISO capacity remains available to sell for PY 16/17 – PY 19/20[1]

~58% of MISO capacity remains available for sale through PY 2019/2020[2]

[1] Load Serving Entities in MISO must have their capacity requirements met for Planning Year 2015/2016 by conclusion of the auction, so Planning Year 2016/2017 is the next period for which Load Serving Entities must procure capacity; [2] Assumes ~6,100 MWs per planning year over PY 2016/2017 – PY 2019/2020

DYNEGY

PJM Capacity Position[1]

PJM Region	Planning Year	Average Price ($/MW-day)	MWs Cleared	Average Price ($/MW-day)	MWs Cleared
		Base Product		Capacity Performance Product	
RTO[2]	2015-2016	$131.91	5,109		
	2016-2017	$61.31	1,651	$134.00	3,992
	2017-2018	$120.28	2,484	$151.50	2,735
	2018-2019	$149.98	1,734	$164.77	3,905
ComEd	2015-2016	$136.04	3,088		
	2016-2017	$75.71	763	$134.00	2,447
	2017-2018	$120.86	1,248	$151.50	2,261
	2018-2019	$200.21	0	$215.20	3,112
MAAC	2015-2016	$167.60	507		
	2016-2017	$119.10	453	$134.00	51
	2017-2018	$120.00	0	$151.50	508
	2018-2019	$149.98	0	$166.80	508
EMAAC	2015-2016	$167.43	535		
	2016-2017	$119.53	485	$134.00	53
	2017-2018	$120.00	8	$151.50	533
	2018-2019	$210.63	0	$225.42	532
ATSI	2015-2016	$427.98	296		
	2016-2017	$115.75	361	$134.00	0
	2017-2018	$121.65	374	$151.50	0
	2018-2019	$149.98	0	$164.80	195

[1] PJM capacity position represent volumes cleared and purchased in primary annual auctions, incremental auctions, and transitional auctions. Also includes bilateral transactions; [2] Includes imports to PJM from IPH-MISO

DYNEGY

ISO-NE/NYISO/CAISO Capacity Positions

Capacity / Resource Adequacy

ISO/Region	Contract Type	Average Price	Size (MWs)	Tenor
ISO-NE[1]	ISO-NE Capacity Auction	$3.32/kw-Mo	3,711	Jun 2015 to May 2016
		$3.25/kw-Mo	3,664	Jun 2016 to May 2017
		$6.99/kw-Mo	2,181	Jun 2017 to May 2018
		$9.66/kw-Mo	2,147	Jun 2018 to May 2019
		$7.03/kw-Mo	2,240	June 2019 to May 2020
NYISO[2][3]	ICAP	$2.19/kw-Mo	1,124	Winter 2015/2016
		$3.37/kw-Mo	822	Summer 2016
		$2.54/kw-Mo	660	Winter 2016/2017
		$3.34/kw-Mo	740	Summer 2017
CAISO[4]	RA Capacity		62	Avg Bilateral Sold Q4 2015
			535	Avg Bilateral Sold Q3 2016
			300	Avg Bilateral Sold Q3 2017
			63	Avg Bilateral Sold Cal 2016
			650	Avg Bilateral Sold Cal 2017
			400	Avg Bilateral Sold Cal 2018
			850	Avg Bilateral Sold Cal 2019

[1] ISO-NE represents capacity auctions results, supplemental auctions and bilateral capacity sales; [2] NYISO represents capacity auction results and bilateral capacity sales; [3] Winter period covers November through April and the Summer period covers May through October; [4] Dynegy is prohibited from disclosing RA capacity sales through 2016 at Moss Landing 6&7

DYNEGY

Appendix
Reg G Reconciliations

DYNEGY

Reg G Reconciliation – 4th Quarter 2014 Adjusted EBITDA

DYNEGY INC.
REPORTED SEGMENTED RESULTS OF OPERATIONS
THREE MONTHS ENDED DECEMBER 31, 2014
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the three months ended December 31, 2014:

	Three Months Ended December 31, 2014				
	Coal	IPH	Gas	Other	Total
Net loss attributable to Dynegy Inc.					$ (104)
Plus / (Less):					
Income attributable to noncontrolling interest					1
Interest expense					119
Depreciation expense					62
Amortization expense					8
EBITDA (1)	$ 48	$ 24	$ 53	$ (39)	$ 86
Plus / (Less):					
Acquisition and integration costs	—	8	—	10	18
Bankruptcy reorganization items, net	—	—	—	(1)	(1)
Income attributable to noncontrolling interest	—	(1)	—	—	(1)
Mark-to-market adjustments	(39)	4	(1)	—	(36)
Change in fair value of common stock warrants	—	—	—	(3)	(3)
Gain on sale of assets, net	—	—	(1)	—	(1)
ARO accretion expense	1	2	—	—	3
Other	1	1	—	—	2
Adjusted EBITDA (1)	$ 11	$ 38	$ 51	$ (33)	$ 67

(1) EBITDA and Adjusted EBITDA are non-GAAP financial measures. Please refer to Item 2.02 of our Form 8-K filed on February 24, 2016, for definitions, utility and uses of such non-GAAP financial measures. A reconciliation of EBITDA to Operating loss is presented below. Management does not allocate interest expense and income taxes on a segment level and therefore uses Operating income (loss) as the most directly comparable GAAP measure.

	Three Months Ended December 31, 2014				
	Coal	IPH	Gas	Other	Total
Operating income (loss)	$ 38	$ 12	$ 7	$ (45)	$ 12
Depreciation expense	12	9	40	1	62
Bankruptcy reorganization items, net	—	—	—	1	1
Amortization expense	(2)	4	6	—	8
Other items, net (1)	—	(1)	—	4	3
EBITDA	$ 48	$ 24	$ 53	$ (39)	$ 86

(1) Other items, net primarily consists of the change in fair value of our common stock warrants.

DYNEGY

Reg G Reconciliation – 4th Quarter 2015 Adjusted EBITDA

DYNEGY INC.
REPORTED SEGMENTED RESULTS OF OPERATIONS
THREE MONTHS ENDED DECEMBER 31, 2015
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the three months ended December 31, 2015:

	Three Months Ended December 31, 2015				
	Coal	IPH	Gas	Other	Total
Net loss attributable to Dynegy Inc.					$ (134)
Plus / (Less):					
Income tax benefit					(1)
Interest expense					133
Depreciation expense					174
Amortization expense					8
EBITDA (1)	$ (33)	$ 15	$ 221	$ (23)	$ 180
Plus / (Less):					
Acquisition and integration costs	—	—	—	3	3
Mark-to-market adjustments	4	(2)	3	—	5
Change in fair value of common stock warrants	—	—	—	(11)	(11)
Impairments	25	—	—	—	25
Cash distributions from unconsolidated investments	—	—	4	—	4
Baldwin transformer project	7	—	—	—	7
ARO accretion expense	2	3	1	—	6
Other	4	—	(1)	—	3
Adjusted EBITDA (1)	$ 9	$ 16	$ 228	$ (31)	$ 222

(1) EBITDA and Adjusted EBITDA are non-GAAP financial measures. Please refer to Item 2.02 of our Form 8-K filed on February 24, 2016, for definitions, utility and uses of such non-GAAP financial measures. A reconciliation of EBITDA to Operating income (loss) is presented below. Management does not allocate interest expense and income taxes on a segment level and therefore uses Operating income (loss) as the most directly comparable GAAP measure.

	Three Months Ended December 31, 2015				
	Coal	IPH	Gas	Other	Total
Operating income (loss)	$ (59)	$ 10	$ 70	$ (34)	$ (13)
Depreciation expense	42	5	126	1	174
Amortization expense	(15)	—	23	—	8
Earnings from unconsolidated investments	—	—	2	—	2
Other items, net (1)	(1)	—	—	10	9
EBITDA	$ (33)	$ 15	$ 221	$ (23)	$ 180

(1) Other items, net primarily consists of the change in fair value of our common stock warrants, the write-off of certain power generation assets and the receipt of casualty insurance proceeds.

Reg G Reconciliation – Prior Year-to-Date Adjusted EBITDA

REPORTED SEGMENTED RESULTS OF OPERATIONS
TWELVE MONTHS ENDED DECEMBER 31, 2014
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the twelve months ended December 31, 2014:

	Twelve Months Ended December 31, 2014				
	Coal	IPH	Gas	Other	Total
Net loss attributable to Dynegy Inc.					$ (273)
Plus / (Less):					
Income attributable to noncontrolling interest					6
Income tax benefit					(1)
Interest expense					223
Depreciation expense					247
Amortization expense					50
EBITDA (1)	$ 85	$ 28	$ 307	$ (168)	$ 252
Plus / (Less):					
Acquisition and integration costs	—	16	—	19	35
Bankruptcy reorganization items, net	—	—	—	(3)	(3)
Income attributable to noncontrolling interest	—	(6)	—	—	(6)
Mark-to-market adjustments	(32)	38	22	—	28
Change in fair value of common stock warrants	—	—	—	40	40
Gain on sale of assets, net	—	—	(18)	—	(18)
ARO accretion expense	6	6	—	—	12
Other	3	1	—	3	7
Adjusted EBITDA (1)	$ 62	$ 83	$ 311	$ (109)	$ 347

(1) EBITDA and Adjusted EBITDA are non-GAAP financial measures. Please refer to Item 2.02 of our Form 8-K filed on February 24, 2016, for definitions, utility and uses of such non-GAAP financial measures. A reconciliation of EBITDA to Operating income (loss) is presented below. Management does not allocate interest expense and income taxes on a segment level and therefore uses Operating income (loss) as the most directly comparable GAAP measure.

	Twelve Months Ended December 31, 2014				
	Coal	IPH	Gas	Other	Total
Operating income (loss)	$ 40	$ (2)	$ 79	$ (136)	$ (19)
Depreciation expense	51	37	155	4	247
Bankruptcy reorganization items, net	—	—	—	3	3
Amortization expense	(6)	(7)	63	—	50
Earnings from unconsolidated investments	—	—	10	—	10
Other items, net (1)	—	—	—	(39)	(39)
EBITDA	$ 85	$ 28	$ 307	$ (168)	$ 252

(1) Other items, net primarily consists of the change in fair value of our common stock warrants.

DYNEGY

Reg G Reconciliation – Current Year-to-Date Adjusted EBITDA

DYNEGY INC.
REPORTED SEGMENTED RESULTS OF OPERATIONS
TWELVE MONTHS ENDED DECEMBER 31, 2015
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the twelve months ended December 31, 2015:

	Twelve Months Ended December 31, 2015				
	Coal	IPH	Gas	Other	Total
Net income attributable to Dynegy Inc.					$ 50
Plus / (Less):					
Loss attributable to noncontrolling interest					(3)
Income tax benefit					(474)
Interest expense					546
Depreciation expense					587
Amortization expense					(6)
EBITDA (1)	$ 5	$ 72	$ 816	$ (193)	$ 700
Plus / (Less):					
Acquisition and integration costs	—	—	—	124	124
Loss attributable to noncontrolling interest	—	3	—	—	3
Mark-to-market adjustments	(31)	(10)	(26)	—	(67)
Change in fair value of common stock warrants	—	—	—	(54)	(54)
Impairments	99	—	—	—	99
Loss on sale of assets, net	—	—	1	—	1
Cash distributions from unconsolidated investments	—	—	12	—	12
Baldwin transformer project	7	—	—	—	7
ARO accretion expense	8	12	1	—	21
Other	4	—	(1)	1	4
Adjusted EBITDA (1)	$ 92	$ 77	$ 803	$ (122)	$ 850

(1) EBITDA and Adjusted EBITDA are non-GAAP financial measures. Please refer to Item 2.02 of our Form 8-K filed on February 24, 2016, for definitions, utility and uses of such non-GAAP financial measures. A reconciliation of EBITDA to Operating income (loss) is presented below. Management does not allocate interest expense and income taxes on a segment level and therefore uses Operating income (loss) as the most directly comparable GAAP measure.

	Twelve Months Ended December 31, 2015				
	Coal	IPH	Gas	Other	Total
Operating income (loss)	$ (93)	$ 49	$ 360	$ (252)	$ 64
Depreciation expense	138	29	416	4	587
Amortization expense	(39)	(6)	39	—	(6)
Earnings from unconsolidated investments	—	—	1	—	1
Other items, net (1)	(1)	—	—	55	54
EBITDA	$ 5	$ 72	$ 816	$ (193)	$ 700

(1) Other items, net primarily consists of the change in fair value of our common stock warrants, the write-off of certain power generation assets and the receipt of casualty insurance proceeds.

DYNEGY

Reg G Reconciliation – Prior Year-to-Date Summary of Cash Flow Information

DYNEGY INC.
SUMMARY CASH FLOW INFORMATION (1)
TWELVE MONTHS ENDED DECEMBER 31, 2014
(UNAUDITED) (IN MILLIONS)

	Twelve Months Ended December 31, 2014		
	Dynegy	IPH	Consolidated
Adjusted EBITDA (2)	$ 264	$ 83	$ 347
Interest payments	(69)	(60)	(129)
Collateral	8	(25)	(17)
Working capital / non-cash adjustments / other changes	(60)	22	(38)
Cash provided by operating activities	143	20	163
Maintenance capital expenditures	(80)	(10)	(90)
Environmental capital expenditures	(7)	(26)	(33)
Collateral	(8)	25	17
Interest accrued on $5.1 billion Notes (held in escrow)	65	—	65
Interest rate swap settlement payments	(18)	—	(18)
Free Cash Flow	$ 95	$ 9	$ 104
Capital expenditures	$ (87)	$ (45)	$ (132)
Proceeds from asset sales, net	18	—	18
Increase in restricted cash	(5,148)	—	(5,148)
Net cash used in investing activities	$ (5,217)	$ (45)	$ (5,262)
Proceeds from long-term borrowings	$ 5,112	$ —	$ 5,112
Proceeds from issuance of preferred stock	400	—	400
Proceeds from issuance of common stock	744	—	744
Repayments of borrowings	(14)	—	(14)
Intercompany revolving promissory note	(17)	17	—
Financing costs from debt issuance	(57)		(57)
Financing costs from equity issuance	(38)		(38)
Interest rate swap settlement payments	(18)	—	(18)
Other financing	(3)	—	(3)
Net cash provided by financing activities	$ 6,109	$ 17	$ 6,126

(1) This presentation is intended to demonstrate the relationship between the performance measure of Adjusted EBITDA and the liquidity measure of Free Cash Flow. We believe it is useful to our analysts and investors to understand this relationship because it demonstrates how the cash generated by our operations is used to satisfy various liquidity requirements. A reconciliation of Free Cash Flow from Net cash provided by (used in) operating activities is presented above. Please refer to Item 2.02 of our Form 8-K filed on February 24, 2015, for definitions, utility and uses of such non-GAAP financial measures.

(2) Adjusted EBITDA is a non-GAAP financial measure. Please refer to Item 2.02 of our Form 8-K filed on February 24, 2015, for definitions, utility and uses of such non-GAAP financial measures. Please see Reported Segmented Results of Operations for the twelve months ended December 31, 2014 for a reconciliation of Adjusted EBITDA to Net loss.

DYNEGY

Reg G Reconciliation – Current Year-to-Date Summary of Cash Flow Information

DYNEGY INC.
SUMMARY CASH FLOW INFORMATION (1)
TWELVE MONTHS ENDED DECEMBER 31, 2015
(UNAUDITED) (IN MILLIONS)

	Twelve Months Ended December 31, 2015		
	Dynegy	IPH	Consolidated
Adjusted EBITDA (2)	$ 773	$ 77	$ 850
Interest payments	(441)	(59)	(500)
Acquisition and integration payments	(115)	—	(115)
Collateral	61	25	86
Hedge adjustment related to acquisitions	(60)	—	(60)
Working capital and other changes	(98)	(69)	(167)
Net cash provided by (used in) operating activities	120	(26)	94
Maintenance capital expenditures	(169)	(28)	(197)
Environmental capital expenditures	(6)	(22)	(28)
Collateral	(61)	(25)	(86)
Interest accrued on $5.1 billion Notes (pre-acquisition interest)	92	—	92
Interest rate swap settlement payments	(17)	—	(17)
Acquisition and integration costs	115	—	115
Hedge adjustment related to acquisitions	60	—	60
Working capital and other changes	84	69	153
Free Cash Flow	$ 218	$ (32)	$ 186
Capital expenditures	$ (212)	$ (63)	$ (275)
(Increase) decrease in restricted cash	5,148	—	5,148
Acquisitions, net of cash acquired/divestitures	(6,078)	—	(6,078)
Distributions from unconsolidated affiliates	8	—	8
Other investing	3	—	3
Net cash used in investing activities	$ (1,131)	$ (63)	$ (1,194)
Proceeds from long-term borrowings	$ 97	$ —	$ 97
Repayments of borrowings	(31)		(31)
Financing costs from debt issuance	(31)	—	(31)
Financing costs from equity issuance	(6)	—	(6)
Dividends paid	(23)	—	(23)
Interest rate swap settlement payments	(17)	—	(17)
Repurchase of common stock	(250)	—	(250)
Other financing	(4)	—	(4)
Net cash used in financing activities	$ (265)	$ —	$ (265)

(1) This presentation is intended to demonstrate the relationship between the performance measure of Adjusted EBITDA and the liquidity measure of Free Cash Flow. We believe it is useful to our analysts and investors to understand this relationship because it demonstrates how the cash generated by our operations is used to satisfy various liquidity requirements. A reconciliation of Free Cash Flow from Net cash provided by (used in) operating activities is presented above. Please refer to Item 2.02 of our Form 8-K filed on February 24, 2016, for definitions, utility and uses of such non-GAAP financial measures.

(2) Adjusted EBITDA is a non-GAAP financial measure. Please refer to Item 2.02 of our Form 8-K filed on February 24, 2016, for definitions, utility and uses of such non-GAAP financial measures. Please see Reported Segmented Results of Operations for the twelve months ended December 31, 2015 for a reconciliation of Adjusted EBITDA to Net income attributable to Dynegy Inc.

Reg G Reconciliation – Dynegy 2015 Adjusted EBITDA and Free Cash Flow Guidance

DYNEGY INC.
2015 ADJUSTED EBITDA AND FREE CASH FLOW GUIDANCE
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our 2015 Adjusted EBITDA guidance, updated based on October 19, 2015 forward curves, as presented on November 4, 2015:

	Dynegy Consolidated	
	Low	High
Net income attributable to Dynegy Inc. (3)	$ 41	$ 111
Plus / (Less):		
Income tax benefit (2)	(473)	(473)
Other items, net (4)	(4)	(4)
Interest expense	537	537
Operating Income	101	171
Depreciation expense	580	600
Amortization expense	(5)	(5)
Other items, net	1	1
EBITDA (1)	677	767
Plus / (Less):		
Transaction fees and expenses	85	90
Integration costs	35	40
Other (5)	28	28
Adjusted EBITDA (1)	$ 825	$ 925

(1) EBITDA and Adjusted EBITDA are non-GAAP measures.

(2) Represents actual amounts for the nine months ended September 30, 2015.

(3) For purposes of Net income attributable to Dynegy Inc. guidance reconciliation, mark-to-market adjustments and changes in the fair value of common stock warrants are assumed to be zero.

(4) Represents actual amounts for the nine months ended September 30, 2015. Other items, net primarily consists of the loss attributable to noncontrolling interest and losses from unconsolidated investments.

(5) Represents actual amounts for the nine months ended September 30, 2015. Other consists primarily of adjustments for losses attributable to noncontrolling interest, cash distributions from unconsolidated investments and asset retirement obligation accretion.

The following table provides summary financial data regarding our 2015 Free Cash Flow guidance:

	Dynegy Consolidated	
	Low	High
Adjusted EBITDA (1)	$ 825	$ 925
Cash interest payments	(517)	(517)
Transaction fees and expenses (2)	(110)	(115)
Integration costs	(35)	(40)
Other non-cash and working capital items	(5)	(5)
Cash Flow from Operations	158	248
Maintenance capital expenditures	(225)	(225)
Environmental capital expenditures	(30)	(30)
Transaction fees and expenses (2)	110	115
Integration costs	35	40
Acquisition interest (3)	92	92
Free Cash Flow (1)	$ 140	$ 240

(1) Adjusted EBITDA and Free Cash Flow are non-GAAP measures.

(2) Consists of nonrecurring transaction costs including a commitment fee on the Bridge Loan Facilities, legal and advisory fees related to the acquisitions, a fee for executing the $950M million Revolver and syndication fees associated with the issuance of the $5.1 billion Notes and Common Stock and Mandatory Convertible Preferred Stock Offerings.

(3) Reflects $92 million of interest on $5.1 billion Notes for the period prior to the close of the acquisitions (January-March).

DYNEGY

Reg G Reconciliation – IPH 2015 Adjusted EBITDA Guidance

ILLINOIS POWER HOLDINGS (IPH)
2015 ADJUSTED EBITDA GUIDANCE
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our IPH 2015 Adjusted EBITDA guidance, updated based on October 19, 2015 forward curves, as presented on November 4, 2015:

Operating Income	$	55
Depreciation expense		36
Amortization expense		(6)
Adjusted EBITDA (1)	$	85

(1) Adjusted EBITDA is a non-GAAP measure. Management does not allocate interest expense and income taxes on a segment level and therefore uses Operating Income (Loss) as the most directly comparable GAAP measure.

Reg G Reconciliation – Dynegy Prior 2016 Adjusted EBITDA and Free Cash Flow Guidance

The following table provides summary financial data regarding our 2016 Adjusted EBITDA guidance, based on October 19, 2015 forward curves, as presented on November 4, 2015:

	Dynegy Consolidated	
	Low	High
Net income (loss) attributable to Dynegy Inc.	$ (152)	$ 23
Plus / (Less):		
Interest expense	542	542
Operating Income	390	565
Depreciation expense	680	700
Amortization expense	30	30
EBITDA (1)	1,100	1,295
Plus / (Less):		
Integration costs	—	5
Adjusted EBITDA (1)	$ 1,100	$ 1,300

(1) EBITDA and Adjusted EBITDA are non-GAAP measures.

The following table provides summary financial data regarding our 2016 Free Cash Flow guidance:

	Dynegy Consolidated	
	Low	High
Adjusted EBITDA (1)	$ 1,100	$ 1,300
Cash interest payments	(515)	(515)
Integration costs	—	(5)
Other non-cash and working capital items	35	35
Cash Flow from Operations	620	815
Maintenance capital expenditures	(300)	(300)
Environmental capital expenditures	(20)	(20)
Integration costs	—	5
Free Cash Flow (1)	$ 300	$ 500

(1) Adjusted EBITDA and Free Cash Flow are non-GAAP measures.

DYNEGY

Reg G Reconciliation – Dynegy 2016 Adjusted EBITDA and Free Cash Flow Guidance

The following table provides summary financial data regarding our 2016 Adjusted EBITDA guidance, based on February 8, 2016 forward curves, as presented on February 24, 2016:

	Dynegy Consolidated	
	Low	High
Net loss attributable to Dynegy Inc.	$ (275)	$ (105)
Plus / (Less):		
Interest expense	535	540
Operating Income	260	435
Depreciation expense	710	730
Amortization expense	30	30
EBITDA (1)	1,000	1,195
Plus / (Less):		
Integration costs	—	5
Adjusted EBITDA (1)	$ 1,000	$ 1,200

(1) EBITDA and Adjusted EBITDA are non-GAAP measures.

The following table provides summary financial data regarding our 2016 Free Cash Flow guidance:

	Dynegy Consolidated	
	Low	High
Adjusted EBITDA (1)	$ 1,000	$ 1,200
Cash interest payments	(515)	(515)
Integration costs	—	(5)
Other cash items	35	35
Cash Flow from Operations	520	715
Maintenance capital expenditures	(300)	(300)
Environmental capital expenditures	(20)	(20)
Integration costs	—	5
Free Cash Flow (1)	$ 200	$ 400

(1) Adjusted EBITDA and Free Cash Flow are non-GAAP measures.

DYNEGY

Reg G Reconciliation – IPH Prior 2016 Adjusted EBITDA Guidance

ILLINOIS POWER HOLDINGS (IPH)
2016 ADJUSTED EBITDA GUIDANCE
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our IPH 2016 Adjusted EBITDA guidance, based on October 19, 2015 forward curves, as presented on November 4, 2015:

Operating Income	**$**	**123**
Depreciation expense		36
Amortization expense		(9)
Adjusted EBITDA (1)	**$**	**150**

(1) Adjusted EBITDA is a non-GAAP measure. Management does not allocate interest expense and income taxes on a segment level and therefore uses Operating Income (Loss) as the most directly comparable GAAP measure.

Reg G Reconciliation – IPH 2016 Adjusted EBITDA Guidance

ILLINOIS POWER HOLDINGS (IPH)
2016 ADJUSTED EBITDA GUIDANCE
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our IPH 2016 Adjusted EBITDA guidance, based on February 8, 2016 forward curves, as presented on February 24, 2016:

Operating Income	$	61
Depreciation expense		48
Amortization expense		(9)
Adjusted EBITDA (1)	$	100

(1) Adjusted EBITDA is a non-GAAP measure. Management does not allocate interest expense and income taxes on a segment level and therefore uses Operating Income (Loss) as the most directly comparable GAAP measure.

Ex. TC - 4

DYNEGY

First Quarter 2016 Review

May 3, 2016

Forward-Looking Statements

Cautionary Statement Regarding Forward-Looking Statements

This presentation contains statements reflecting assumptions, expectations, projections, intentions or beliefs about future events that are intended as "forward looking statements." You can identify these statements by the fact that they do not relate strictly to historical or current facts. Management cautions that any or all of Dynegy's forward-looking statements may turn out to be wrong. Please read Dynegy's annual, quarterly and current reports filed under the Securities Exchange Act of 1934, including its 2015 Form 10-K and first quarter 2016 Form 10-Q, when filed, for additional information about the risks, uncertainties and other factors affecting these forward-looking statements and Dynegy generally. Dynegy's actual future results may vary materially from those expressed or implied in any forward-looking statements. All of Dynegy's forward-looking statements, whether written or oral, are expressly qualified by these cautionary statements and any other cautionary statements that may accompany such forward-looking statements. In addition, Dynegy disclaims any obligation to update any forward-looking statements to reflect events or circumstances after the date hereof.

Non-GAAP Financial Measures

This presentation contains non-GAAP financial measures including EBITDA, Adjusted EBITDA and Free Cash Flow. Reconciliations of these measures to the most directly comparable GAAP financial measures to the extent available without unreasonable effort are contained herein. To the extent required, statements disclosing the definitions, utility and purposes of these measures are set forth in Item 2.02 to our current report on Form 8-K filed with the SEC on May 3, 2016, which is available on our website free of charge, www.dynegy.com.

Table of Contents

DYNEGY

Overview and Outlook

2016 Financial Performance	• 1Q16 Adjusted EBITDA of $251 MM versus $85 MM in 1Q15 • Acquired assets contributed $209 MM to 1Q16 Adjusted EBITDA • Dynegy Inc. liquidity at 3/31/2016 totaled $1,727 MM, with $743 MM in unrestricted cash
Capacity Markets	• $172 MM in future MISO capacity revenues secured in 1Q16 • $189 MM in future ISO-NE capacity revenues secured in 1Q16, which included 70 MW of uprates qualifying for a seven year rate-lock beginning in PY 19/20 • $17 MM in future NYISO capacity revenues secured in 1Q6
Portfolio Developments	• Baldwin Units 1 & 3 and Newton Unit 2 to be mothballed, with an additional 500 MW targeted for further rationalization • MISO approved Wood River for retirement by 6/1/2016 • Efforts underway to resolve Genco subsidiary
2016 Outlook	• 2016 Adjusted EBITDA and Free Cash Flow guidance affirmed • Impact of unsold MISO capacity offset by lower O&M and CapEx • 2016 hedges at ~70% for Coal segment, ~65% for IPH and ~60% for Gas segment

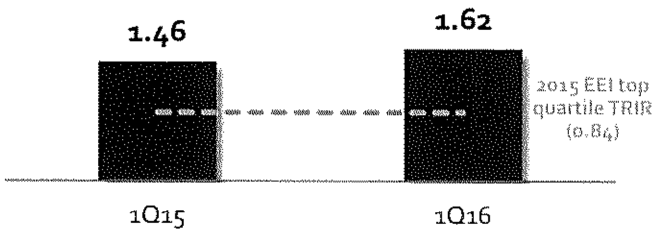
Note: Adjusted EBITDA and Free Cash Flow are non-GAAP measures; reconciliations to GAAP can be found in the Appendix

First Quarter 2016 Results and Guidance

OPERATIONAL

Safety Performance

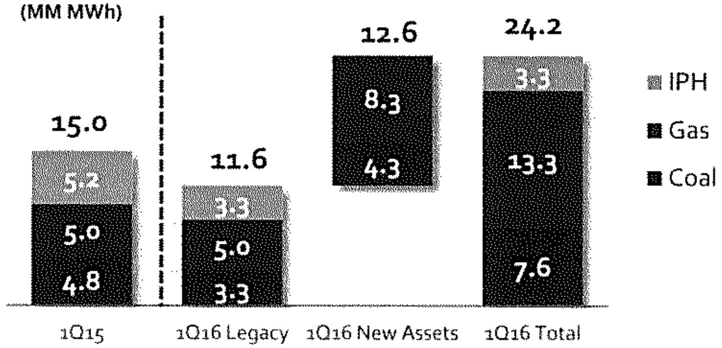
Total Recordable Incident Rate (TRIR)



- No Gas segment employee recordable incidents in 1Q16
- Initiatives to improve safety performance are underway through collaborative efforts with management and unions

Volumes Generated

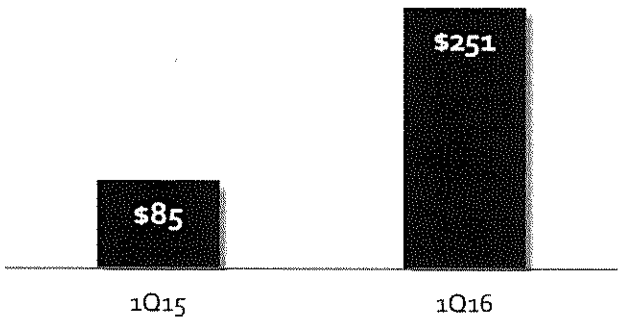
(MM MWh)



- Legacy Coal segment and IPH volumes decreased due to mild winter weather across our key markets resulting in weaker capacity factors
- 1Q generation output records were set in 2016 at Liberty, Ontelaunee, Washington, Hanging Rock and Kendall

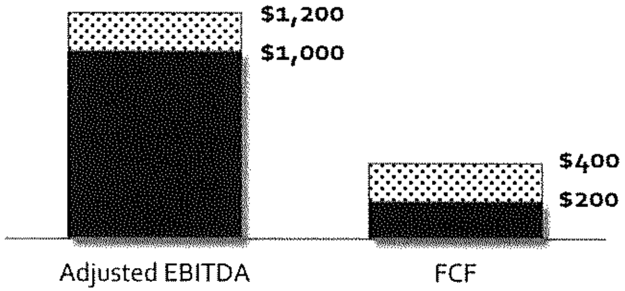
FINANCIAL

Adjusted EBITDA ($ MM)



- Increase in Adjusted EBITDA primarily driven by acquired assets and higher capacity sales at IPH
- Gains tempered by impact of mild winter weather

2016 Adjusted EBITDA and FCF Guidance ($ MM)



- Affirming 2016 Adjusted EBITDA and Free Cash Flow guidance

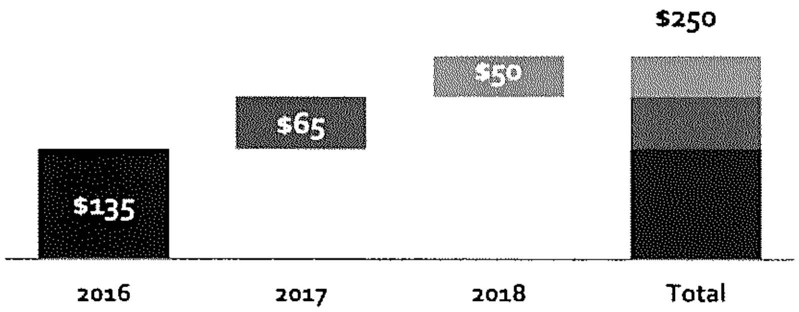
Note: Adjusted EBITDA and Free Cash Flow are non-GAAP measures; reconciliations to GAAP can be found in the Appendix

DYNEGY

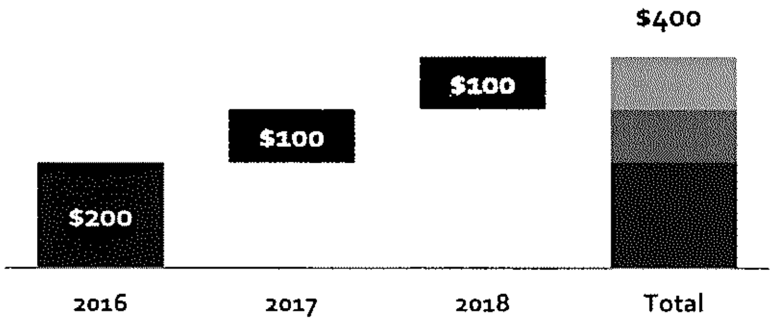
PRIDE Energized (2016 – 2018)

GOALS

2016 – 2018 PRIDE Energized EBITDA ($ MM)

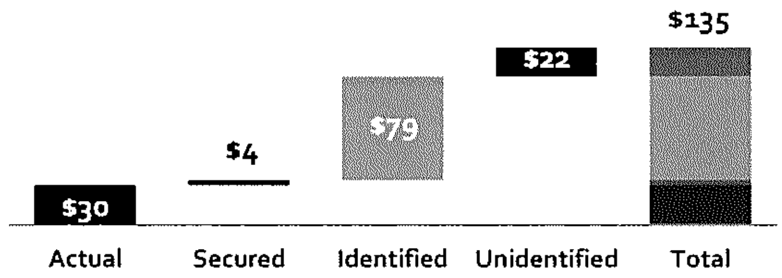


2016 – 2018 PRIDE Energized Balance Sheet ($ MM)

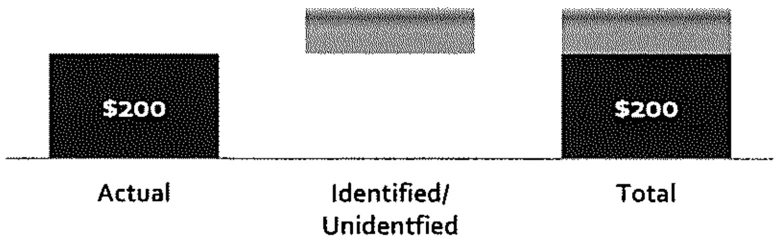


2016 PROGRESS

2016 PRIDE EBITDA Initiatives ($ MM)



2016 PRIDE Balance Sheet Initiatives ($ MM)



PRIDE Energized remains on target

DYNEGY

ENGIE Transaction Update

Regulatory

- Filed Section 203 applications with FERC on March 25, 2016 – comment deadline of May 24, 2016
- Hart-Scott-Rodino early termination received for both ENGIE acquisition and ECP's proposed investment in Dynegy
- Filed applications with the New York PUC on March 24, 2016 and with the Texas PUC on March 25, 2016

Financing

- $198 MM in cash received from the monetization of PJM capacity
- $100 MM in Dynegy Inc. liquidity added in the form of additional liquidity facility commitments
- $25 MM in bank revolver commitments for the joint venture

Integration

- Integration plan completed and underway
- Targeted operating model defined
- Synergies on track to meet initial $90 MM target
- Additional synergies being identified

Transaction on track for a 4Q16 close

DYNEGY

Implications from 2016/2017 MISO Capacity Auction

1. Approximately 90% of cleared capacity offered at $0, primarily by utilities outside of Illinois
2. Utilities outside of Illinois receive significant compensation for their capacity from state regulators
3. Results in competitive generators, primarily in Zone 4 (central & southern Illinois), unable to receive compensation required to cover plant costs

Requires Dynegy to make strategic MISO portfolio shift to avoid reliance on capacity auction

Right-size the fleet to match generation supply with retail and wholesale sales and PJM exports

Significant Generation to Exit MISO Zone 4

Baldwin Unit 1
- Estimated Mothball: Oct 2016
- 590 MW
- COD: 1970
- Expected jobs lost: 71 (64 union)

Newton Unit 2
- Estimated Mothball: Sep 2016
- 615 MW
- COD: 1977
- Expected jobs lost: 47 (41 union)

Total Impact
- **2,300 MW** to exit MISO Zone 4
- **280** expected jobs lost (250 union)
- Additional **500 MW** targeted for shutdown

Baldwin Unit 3
- Estimated Mothball: Mar 2017
- 630 MW
- COD: 1975
- Expected jobs lost: 72 (64 union)

Wood River[1]
- Retirement: Jun 2016
- 465 MW
- COD: 1954 (Unit 4); 1964 (Unit 5)
- Expected jobs lost: 90 (81 union)

Highest cost units to shut down

[1] Retirement plans announced on 3Q15 earnings call

DYNEGY

Genco/IPH Over Time

2013

- Signed transaction agreement with Ameren March 14, 2013
- Ameren funded IPH ~$230 MM in cash before closing
- Cash purchase price of $0 by Dynegy Inc.
- Structured as a non-recourse "ring fenced" subsidiaries

2014-2016

- Significant benefits accrued to Genco/IPH under Dynegy ownership
  - $95 MM per year in synergies
  - $101 MM in additional PRIDE benefits, including $31 MM reduction in Newton scrubber cost
- Significant Dynegy management time spent managing Genco/IPH
  - Separate Genco board including independent director
  - Separate financial reporting/annual audits
  - Maintaining/commercializing assets; business protocols
- Focused efforts on not compromising the "ring fence"

Today

- Weak energy pricing and unsold capacity have financially stretched Genco subsidiary
- High cost Genco unit(s) to be shut down
- Liquidity at Genco of $55 MM at 3/31/2016
- $300 MM debt maturity in 2018
- Currently deferring tax payments and monthly service charge
- Management intends to resolve this situation by either:
  1. Restructuring the Genco debt to achieve a sustainable business model, or
  2. Transitioning ownership of Genco plants

Management targeting Genco resolution in 2016

DYNEGY

MISO Hybrid Model Does Not Work for Competitive Generators

Regulated Utility Model	Hybrid Model (MISO)	Competitive Market Model
+ Financial returns virtually assured + Familiar — Inefficient — Expensive for consumers — Less innovative — Ratepayers bear risk	— Divergent interests lead to conflicted market design — Proper price formation does not occur — Volatility without efficiency — Competitive generators unable to receive adequate compensation	+ Drives efficiency by rewarding the most economic suppliers + Lower prices and additional choices for consumers + Drives innovation + Private investors bear risk — Less familiar
Re-regulate	With the Status Quo, generation in central and southern Illinois disappears	**Re-design** (Carve out Zone 4 or join PJM)

Illinois Has a Choice

Status quo for Zone 4 is not sustainable and only the State of Illinois can fix it

DYNEGY

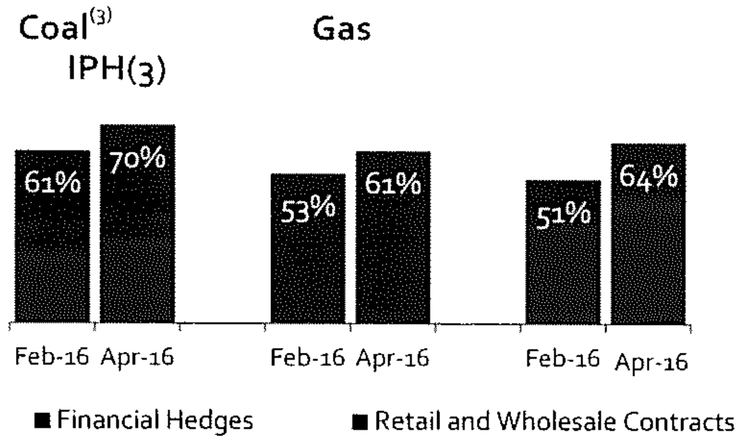
Commercial Overview

Hank Jones, Chief Commercial Officer

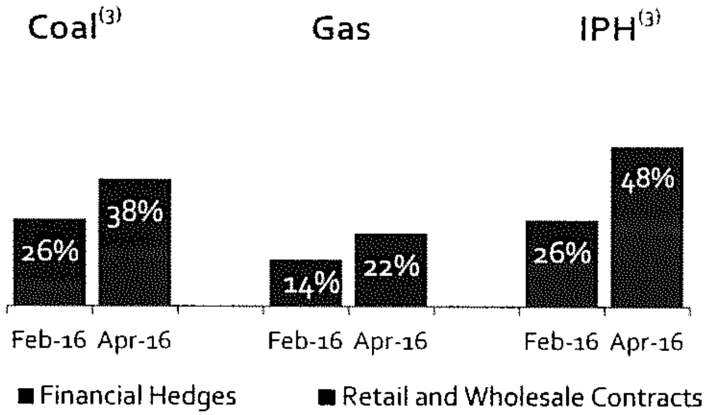
DYNEGY

Commercial Update

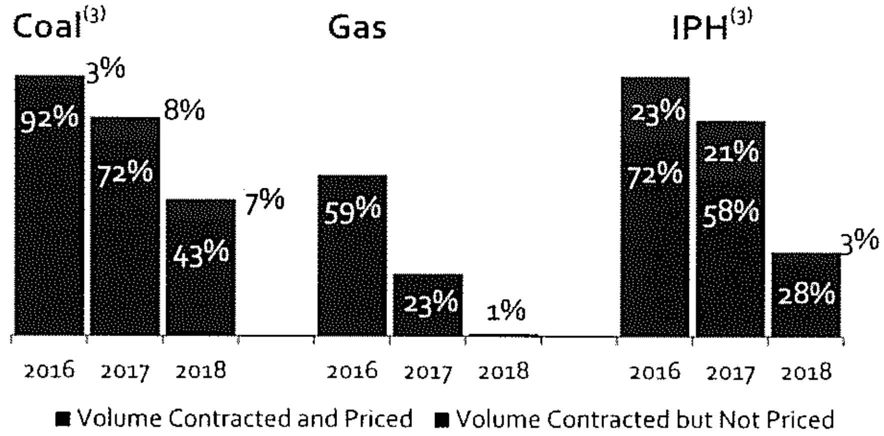
2016 Generation Volumes Hedged by Segment[1]



2017 Generation Volumes Hedged by Segment[2]



Fuel Supply Hedged[2]



Contracted Rail and Barge Transportation	2016	2017	2018-2020
Coal segment	100%	99%	67%
IPH	100%	100%	58%

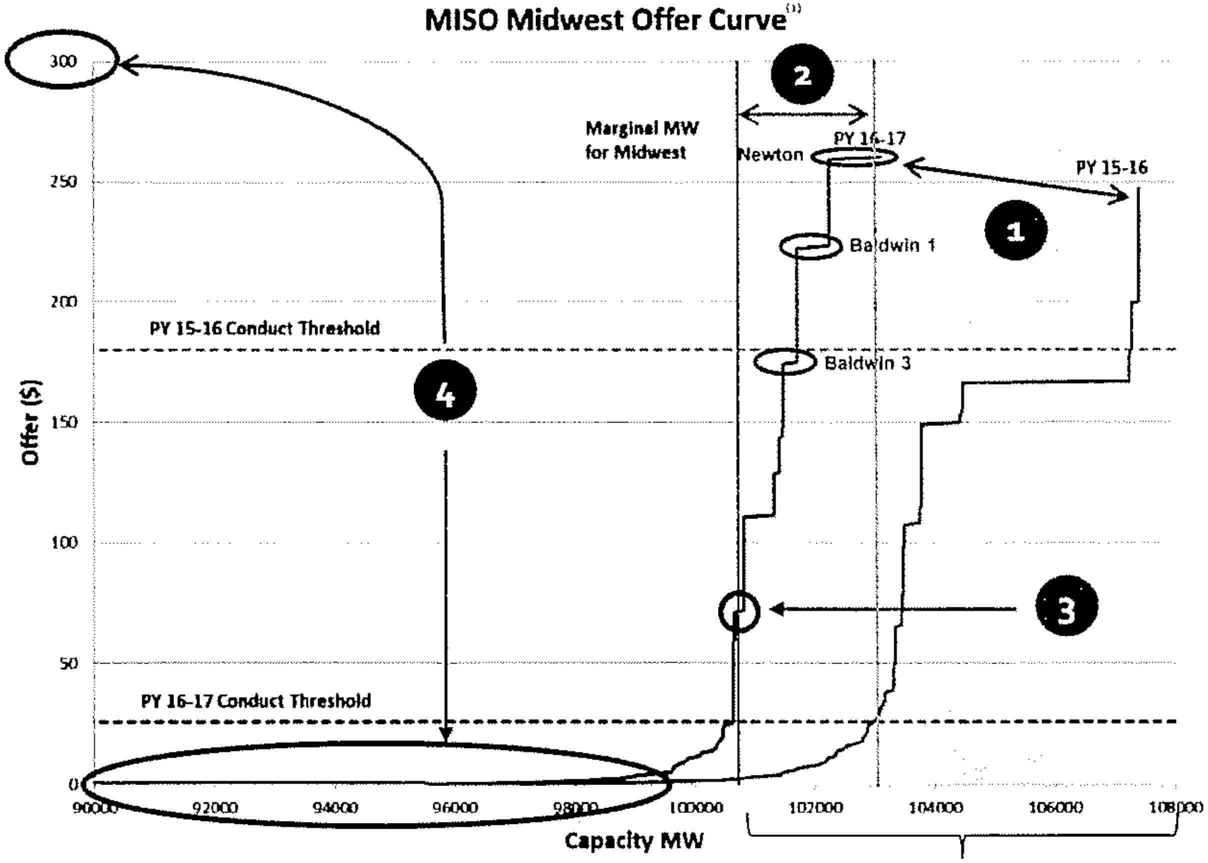
- 2016 Gas segment hedges lock in attractive spark spreads and remaining open position provides protection against declining gas prices
- Gas segment hedges concentrated in PJM, New York and New England
- IPH hedge activity driven by retail sales
- 2016 on-peak Coal segment ~76% hedged for balance of year

(1) Balance of the year as of 2/8/2016 and 4/19/2016; (2) As of 4/19/2016; (3) 2016 excludes Brayton Point & Wood River; 2017-2018 excludes Brayton Point, Wood River, Baldwin Units 1 & 3 and Newton Unit 2

DYNEGY

MISO Planning Year 2016/2017 Auction

MISO Midwest Offer Curve[1]



Offers above $72 per MW/day receive no compensation

1. **Lower supply:** Retirements and exports lowered supply by ~4 GW
2. **Capacity requirement decreased:** MISO decreased the 2016/2017 capacity requirement by ~2 GW
3. **Clearing price unable to address rising costs, tight energy margins:** Given lower energy margins, merchant generation needs higher capacity revenues to cover costs. Dynegy's cost based offers approved by the IMM exceeded the $72 per MW-day clearing price
4. **Hybrid market design suppresses capacity pricing:** Regulated utilities recover on average ~$300/MW-day for capacity through rate base resulting in their units being offered in at little to no cost

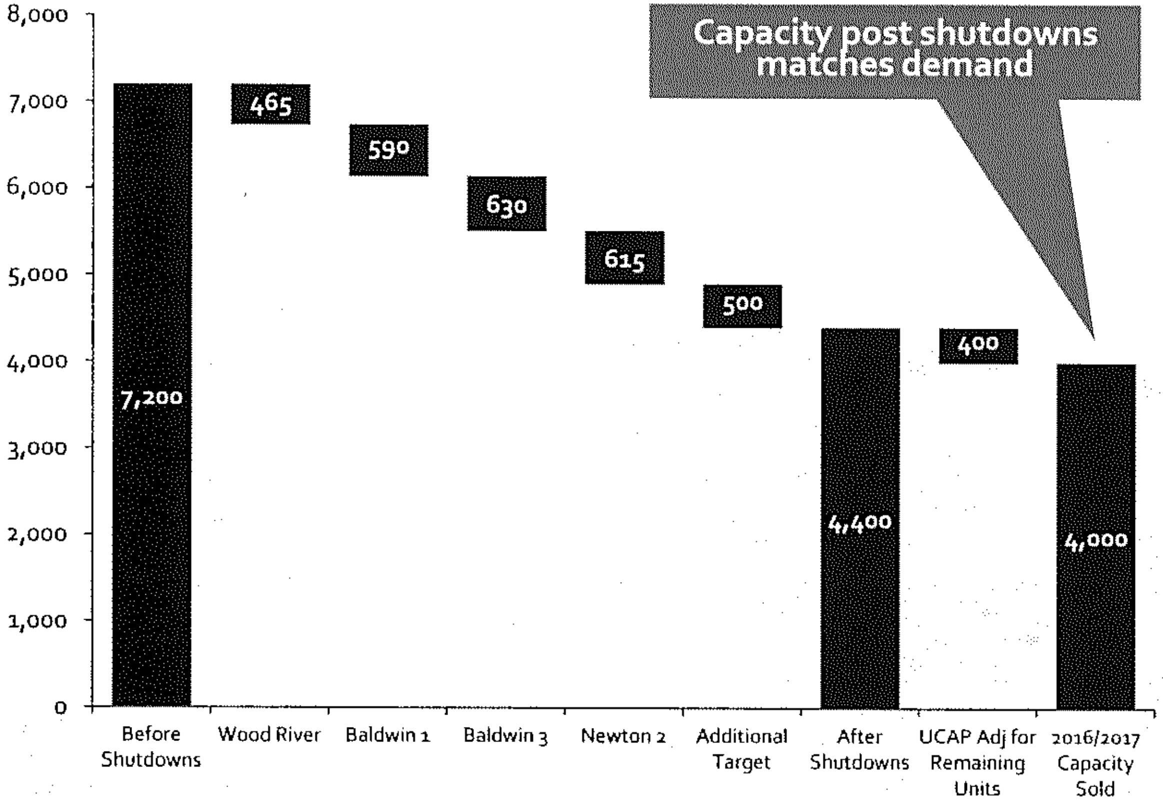
Current construct leaves over 2,000 MW of Dynegy's and IPH's MISO generation without cost recovery

[1] Source: MISO's 2016/17 Planning Resource Auction Results report released on April 14, 2016

DYNEGY

Right-sizing our MISO Portfolio

Changes to Central and Southern IL Generation (MW)



Capacity Summary

- ~$533 million in future committed capacity sales for planning years 2016/2017 through 2019/2020
- Planning Year 2016/2017 Sold Capacity:
  - ~800 MW of exports to PJM
  - ~475 MW of wholesale
  - ~900 MW of bilateral
  - ~1,825 MW of retail

Right-sizing of MISO portfolio to match customer requirements and eliminate Dynegy's reliance on the MISO auction

DYNEGY

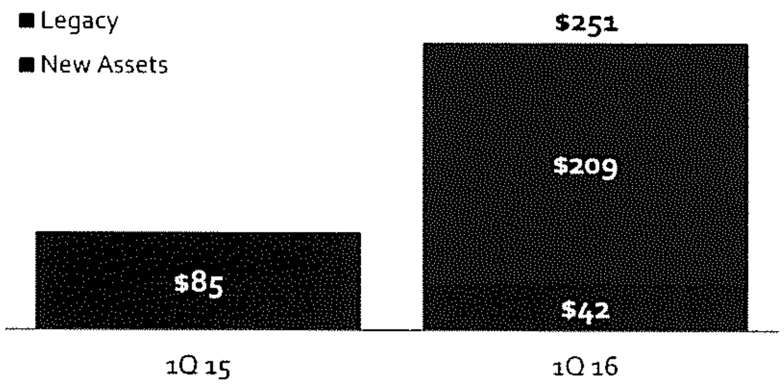
First Quarter 2016 Financial Results

Clint C. Freeland, CFO

DYNEGY

Financial Summary

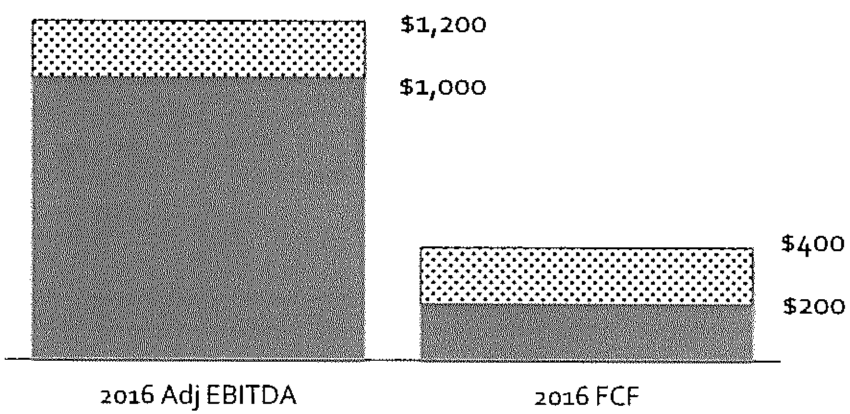
Adjusted EBITDA Results[1] ($ MM)



Liquidity as of 3/31/16[2] ($ MM)

Unrestricted Cash at Dynegy Inc.	$743
Revolver Capacity at Dynegy Inc.	$984
Total Dynegy Inc. Liquidity (excluding IPH)	**$1,727**
Unrestricted Cash at IPH	$78
Revolver Capacity at IPH	$4
Total IPH Liquidity	**$82**

Guidance ($ MM)



Financial Update

Q1 Results
- Continued strong contributions from the assets acquired in 2Q15, primarily the PJM gas assets
- Mild winter weather led to lower generation volumes in the Coal and IPH segments
- Lower Independence spark spreads

Liquidity
- Received $198 MM in cash proceeds from the monetization of planning year 2017/2018 and 2018/2019 PJM capacity auction volumes

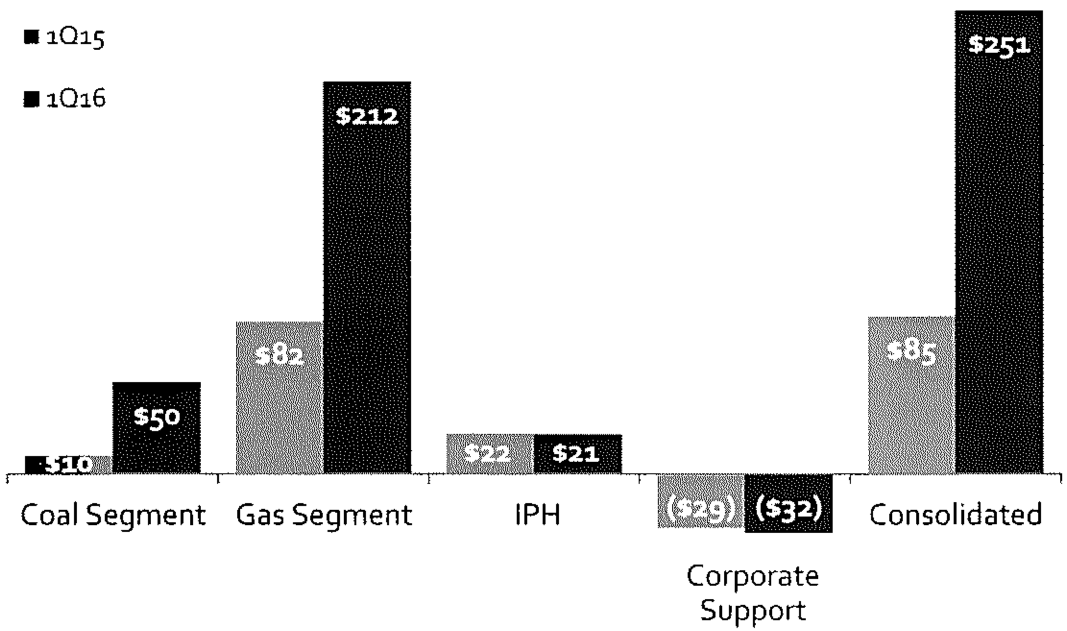
Guidance
- Affirming 2016 Adjusted EBITDA Guidance of $1,000 - 1,200 MM
- Affirming 2016 FCF guidance of $200-400 MM

(1) Corporate overhead included in legacy Adjusted EBITDA; (2) See Appendix for additional detail. Note: Adjusted EBITDA and Free Cash Flow are non-GAAP measures; reconciliations to GAAP can be found in the Appendix

DYNEGY

First Quarter Period-over-Period Segment Performance

1Q Period-over-Period Adjusted EBITDA ($ MM)



Coal Segment	
New Assets	$56 MM
Energy Margin	($17) MM
Wholesale Capacity	$4 MM
Retail and Other O&M	($3) MM
Gas Segment	
New Assets	$153 MM
Energy Margin	($18) MM
O&M	($7) MM
IPH	
Wholesale Capacity	$23 MM
Energy Margin	($22) MM
Retail and Other GM	($8) MM
O&M	$6 MM

New assets and higher IPH capacity revenues benefit quarterly results

DYNEGY

Affirming 2016 Adjusted EBITDA and Free Cash Flow Guidance[1]

Consolidated Dynegy Inc. ($ MM)	
Adjusted EBITDA	$1,000 - 1,200
Maintenance CapEx	($275)
Recurring Environmental CapEx	($20)
Cash Interest	($515)
Other Cash Impacts	$10
Free Cash Flow	$200 - 400

Items to Note

- Guidance affirmation based on April 19, 2016 forward curves
- Forecast excludes Wood River
- Forecast includes Newton Unit 2 and Baldwin Units 1 & 3 through the end of the year
- IPH Adjusted EBITDA, before G&A allocations, estimated at $100 MM
- Capital Allocation (Excluded from Free Cash Flow)
  - DI: $30 MM in Mandatory Dividends/Term Loan Amortization & ~$30 MM in gas plant uprates
  - IPH: ~$10 MM in non-recurring environmental spend for the Newton scrubber and remediation work at Joppa

[1]As presented on February 24, 2016. Note: Adjusted EBITDA and Free Cash Flow are non-GAAP measures; reconciliations to GAAP can be found in the Appendix

Summary

Robert C. Flexon, President and CEO

DYNEGY

Key Takeaways

Strong contributions from acquired assets validates portfolio strategy

ENGIE closing and integration on schedule for 4Q16

MISO strategy modified to eliminate reliance on future capacity auctions

Efforts underway to resolve Genco subsidiary

Appendix – Genco and IPH

Current Economics for IPH Entities

Power Supply Agreement (PSA) cancellable by either party with 6 months notice

Dynegy Inc.
Commercial/Retail/Treasury

$25 MM Revolver

New Wholesale/Retail contracts

Service Agreement

$125+ MM Annual PSA value transfer[1]

$25+ MM Annual PSA subsidy[1]

Genco
Merchant Generation

- $825 MM of debt
- $59 MM of annual interest
- ~$200 MM scrubber spend
- ~$80 MM in ELG, CCR, 316(b) capital spend
- ~$65 MM in CCR ARO spend
- G&A/O&M support costs

RING FENCE

IPRG
Merchant Generation

- ~$45 MM in ELG, CCR, 316(b) capital spend
- ~$45 MM in CCR ARO spend
- G&A/O&M support costs

IPM
Customer Facing Entity

- ~$80 MM of cash/LC collateral posted
- G&A/O&M support costs

(1) Estimated impact for 2016 and beyond

DYNEGY

IPH Subsidiary Level Financial Information ($ MM)

	2015 Genco Standalone Before PSA Subsidy	PSA Subsidy	2015 Genco 10-K		IPH Total (Dynegy Inc. 10-K)
Net Loss attributable to Genco			($562)		
Plus: Impairment			$855		
Plus: Depreciation & Amortization			$86		
Plus: Interest Expense			$39		
Plus: ARO Accretion Expense			$9	Plus IPRG/IPM Results Post-PSA	
Less: Income Tax Benefit			($378)		
Adjusted EBITDA			$49		
Plus: Corp G&A Allocation			$21		
Adj EBITDA Before Allocation of Corp G&A	**($55)**	**$125**	**$70**		**$77**
Less:					
CAPEX	($36)		($36)		($50)
Cash Interest Expense	($59)		($59)		($59)
FCF	($150)	$125	($25)		($32)
G&A Allocation	($21)		($21)		($31)
FCF After G&A Allocation	**($171)**	**$125**	**($46)**		**($63)**

Note: Adjusted EBITDA and Free Cash Flow are non-GAAP measures; reconciliations to GAAP can be found in the Appendix

DYNEGY

Appendix

DYNEGY

Dynegy Generation Facilities

Portfolio/Facility[1]	Location	Net Capacity[2]	Primary Fuel	Dispatch Type	Market Region
Coal Segment					
Baldwin	Baldwin, IL	1,815	Coal	Baseload	MISO
Havana[3]	Havana, IL	434	Coal	Baseload	MISO
Hennepin	Hennepin, IL	294	Coal	Baseload	MISO
Wood River	Alton, IL	465	Coal	Baseload	MISO
Stuart*	Aberdeen, OH	904	Coal	Baseload	PJM
Miami Fort 7&8*	North Bend, OH	653	Coal	Baseload	PJM
Miami Fort CT	North Bend, OH	75	Oil – CT	Peaking	PJM
Zimmer*	Moscow, OH	628	Coal	Baseload	PJM
Conesville*	Conesville, OH	312	Coal	Baseload	PJM
Killen*	Manchester, OH	204	Coal	Baseload	PJM
Kincaid	Kincaid, IL	1,108	Coal	Baseload	PJM
Brayton Point	Somerset, MA	1,528	Coal	Baseload	ISO-NE
Coal Segment TOTAL		**8,420**			
IPH					
Coffeen	Coffeen, IL	915	Coal	Baseload	MISO
Joppa*[4]	Joppa, IL	802	Coal	Baseload	MISO
Joppa CT 1-3[4]	Joppa, IL	165	Gas – CT	Peaking	MISO
Joppa CT 4-5*[4]	Joppa, IL	56	Gas – CT	Peaking	MISO
Newton	Newton, IL	1,230	Coal	Baseload	MISO
Duck Creek	Canton, IL	425	Coal	Baseload	MISO
E.D. Edwards	Bartonville, IL	585	Coal	Baseload	MISO
IPH TOTAL		**4,178**			

NOTES:

1) Dynegy owns 100% of each unit listed except for those marked by an asterisk (*). Total Net Capacity set forth in this table for partially owned units includes only Dynegy's proportionate share of that facility's gross generating capacity.
2) Unit capabilities are based on winter capacity ratings.
3) Represents Unit 6 generating capacity.
4) Not located within MISO.

DYNEGY

Dynegy Generation Facilities, cont.

Portfolio/Facility[1]	*Location*	*Net Capacity*[2]	*Primary Fuel*	*Dispatch Type*	*Market Region*
Gas Segment					
Casco Bay	Veazie, ME	538	Gas – CCGT	Intermediate	ISO-NE
Milford	Milford, CT	569	Gas – CCGT	Intermediate	ISO-NE
Lake Road	Dayville, CT	857	Gas – CCGT	Intermediate	ISO-NE
Dighton	Dighton, MA	185	Gas – CCGT	Intermediate	ISO-NE
Masspower	Indian Orchard, MA	280	Gas – CCGT	Intermediate	ISO-NE
Independence	Oswego, NY	1,126	Gas – CCGT	Intermediate	NYISO
Kendall	Minooka, IL	1,236	Gas – CCGT	Intermediate	PJM
Ontelaunee	Reading, PA	567	Gas – CCGT	Intermediate	PJM
Hanging Rock	Ironton, OH	1,439	Gas – CCGT	Intermediate	PJM
Washington	Beverly, OH	678	Gas – CCGT	Intermediate	PJM
Fayette	Masontown, PA	696	Gas – CCGT	Intermediate	PJM
Liberty	Eddystone, PA	598	Gas – CCGT	Intermediate	PJM
Dicks Creek	Monroe, OH	143	Gas – CT	Peaking	PJM
Lee	Dixon, IL	757	Gas – CT	Peaking	PJM
Elwood*	Elwood, IL	788	Gas – CT	Peaking	PJM
Richland	Defiance, OH	418	Gas – CT	Peaking	PJM
Stryker	Stryker, OH	17	Oil – CT	Peaking	PJM
Moss Landing	Moss Landing, CA				
Units 1-2		1,020	Gas – CCGT	Intermediate	CAISO
Units 6-7		1,509	Gas – CT	Peaking	CAISO
Oakland	Oakland, CA	165	Oil – CT	Peaking	CAISO
Gas Segment TOTAL		**13,586**			
TOTAL GENERATION		**26,184**			

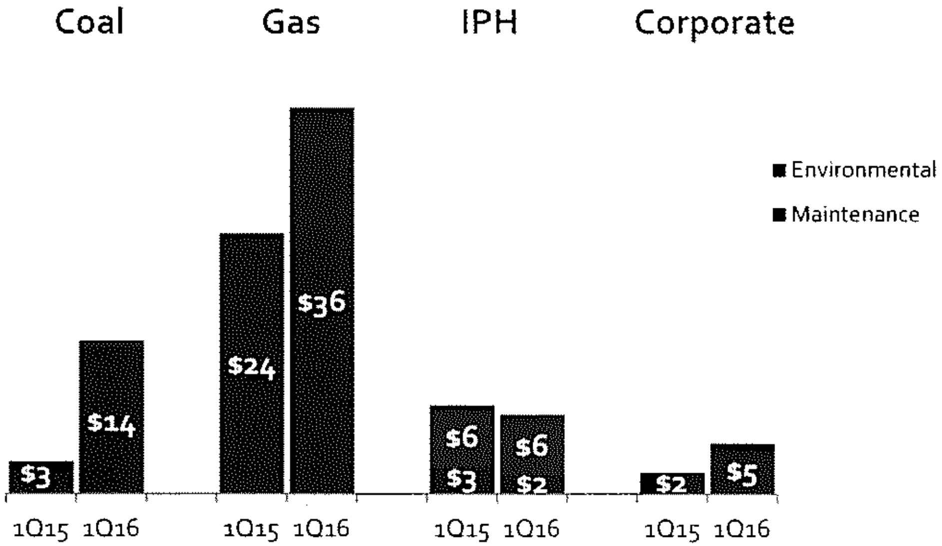
NOTES:

1) Dynegy owns 100% of each unit listed except for those marked by an asterisk (*). Total Net Capacity set forth in this table for partially owned units includes only Dynegy's proportionate share of that facility's gross generating capacity.
2) Unit capabilities are based on winter capacity ratings.
3) Represents Unit 6 generating capacity.
4) Not located within MISO.

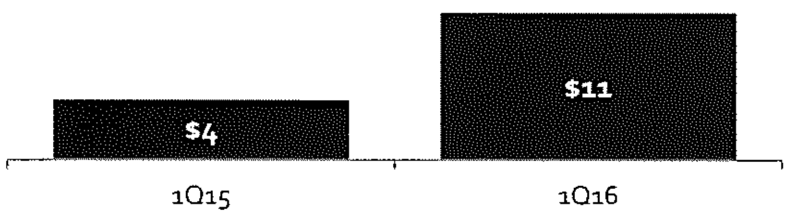
DYNEGY

Capital and Major Maintenance O&M Expenditures Year-Over-Year

Capital Expenditures by Segment[1][2] ($ MM)



Total Major Maintenance Expense ($ MM)



Coal Segment

- Capital spending increased due to the addition of the Duke Midwest and ECP fleets, including a complete generator replacement at Zimmer[3]

Gas Segment

- Capital spending increased due to the addition of the Duke Midwest and ECP fleets

IPH

- Capital spending relatively flat year over year

Corporate

- Capital spending increased primarily due to office HQ expansion

Coal, Gas, and IPH Segments

- Increase in maintenance expense mostly due to the addition of the Duke Midwest and ECP fleets

(1) Excludes capitalized interest; (2) Excludes discretionary investments for growth and reliability; (3) Costs associated with the Zimmer generator replacement expected to be mostly offset by insurance proceeds projected to be received by the end of 2016

DYNEGY

Cost Savings from Portfolio Rationalization

Annual Run Rate Post Shutdowns (in ~$MM)

	Baldwin	Newton	Wood River	Brayton Point	Total
O&M	$50	$30	$5	$5	$90
Maintenance CapEx	$10	$5	-	-	$15
Environmental CapEx	$5	-	-	-	$5
Total	**$65**	**$35**	**$5**	**$5**	**$110**

Total 5 Year Cost Savings (in ~$MM)

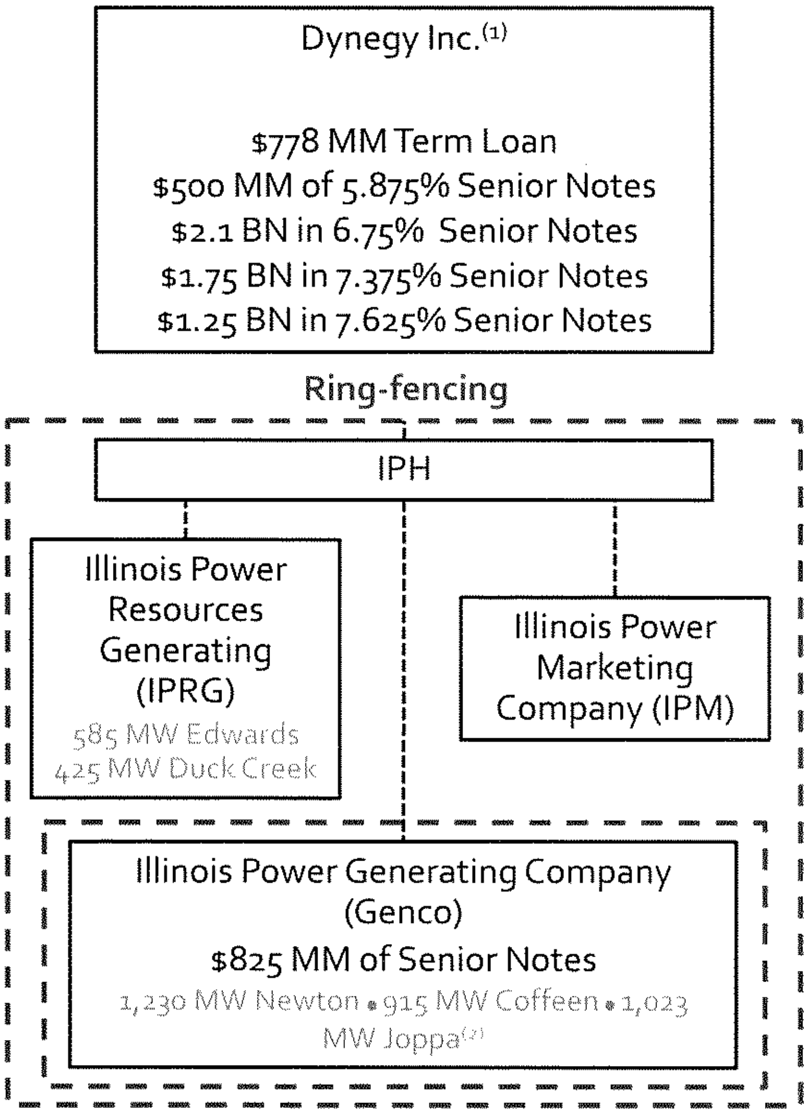
	Baldwin	Newton	Wood River	Brayton Point	Total
O&M	$200	$75	$110	$105	$490
Maintenance CapEx	$110	$45	$40	-	$195
Environmental CapEx	$5	-	$5	-	$10
Total	**$315**	**$120**	**$155**	**$105**	**$695**

Significant Costs Can Be Avoided Shutting Down Units:

- Residual costs at Baldwin and Newton to maintain mothball status and operate surviving units
- Annual O&M for fully retired sites such as Wood River primarily reflect property taxes and site security
- Does not reflect removal of Newton scrubber spend
- Expect to identify additional savings as mothball strategy is executed and cost estimates are refined

Meaningful changes to cost structure as units cease operations

Debt, Liquidity, and Ring-fencing (as of 3/31/2016)



Available Liquidity ($ MM)

Cash and Equivalents	$743
Revolver Capacity	*$1,480*
Outstanding LCs	*($496)*
Revolver Availability	$984
Total DI Liquidity	**$1,727**

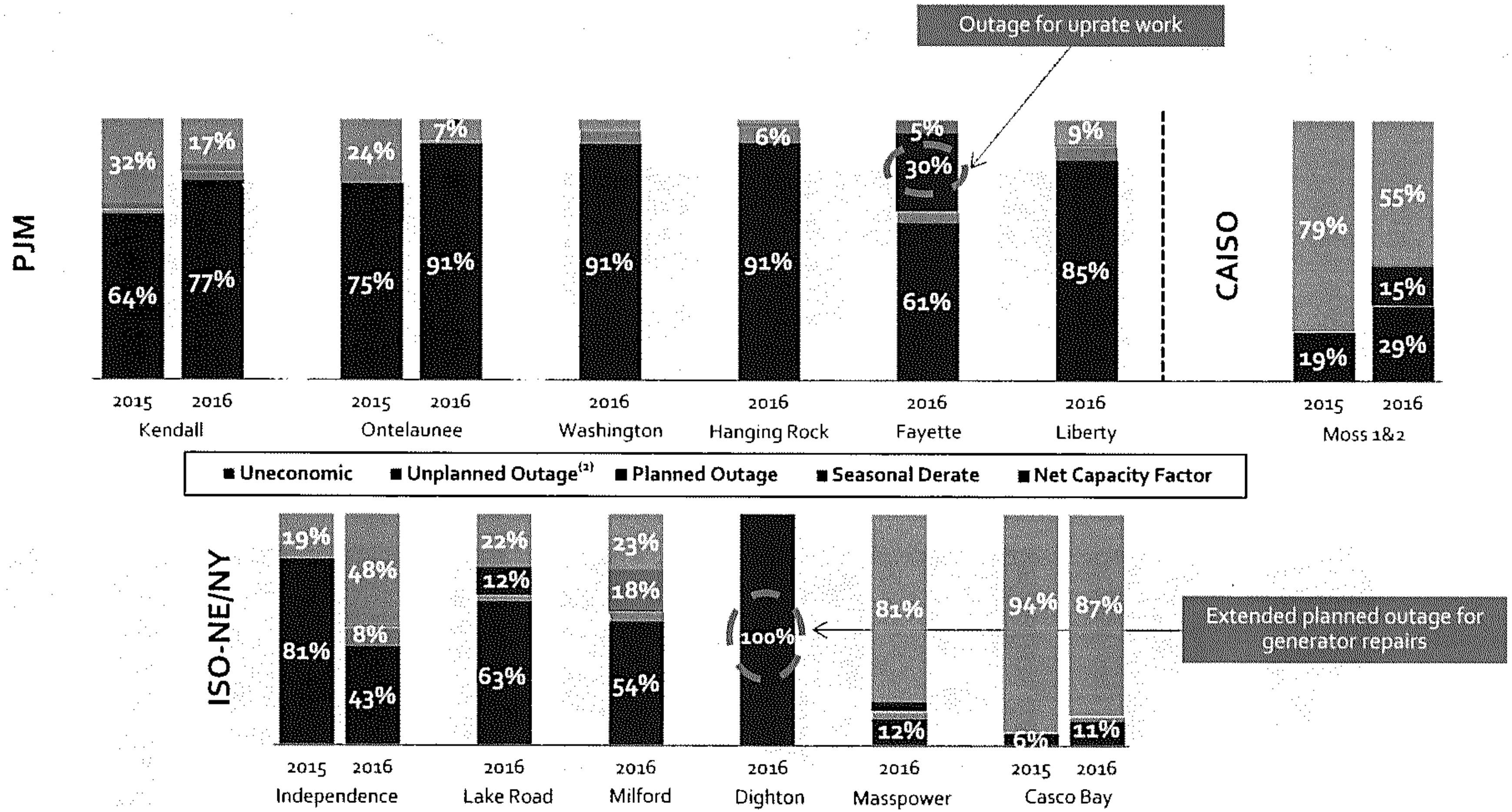
Cash and Equivalents[3]	$78
Revolver Capacity	*$39*
Outstanding LCs	*($35)*
Revolver Availability	$4
Total IPH Liquidity	**$82**

(1) Excludes $76 MM of nonrecourse Elwood Senior Notes; (2) Reflects 80% stake; (3) Genco cash of $55 million

DYNEGY

1Q16 Fleet Performance – Gas Segment

Net Capacity Factors[1]



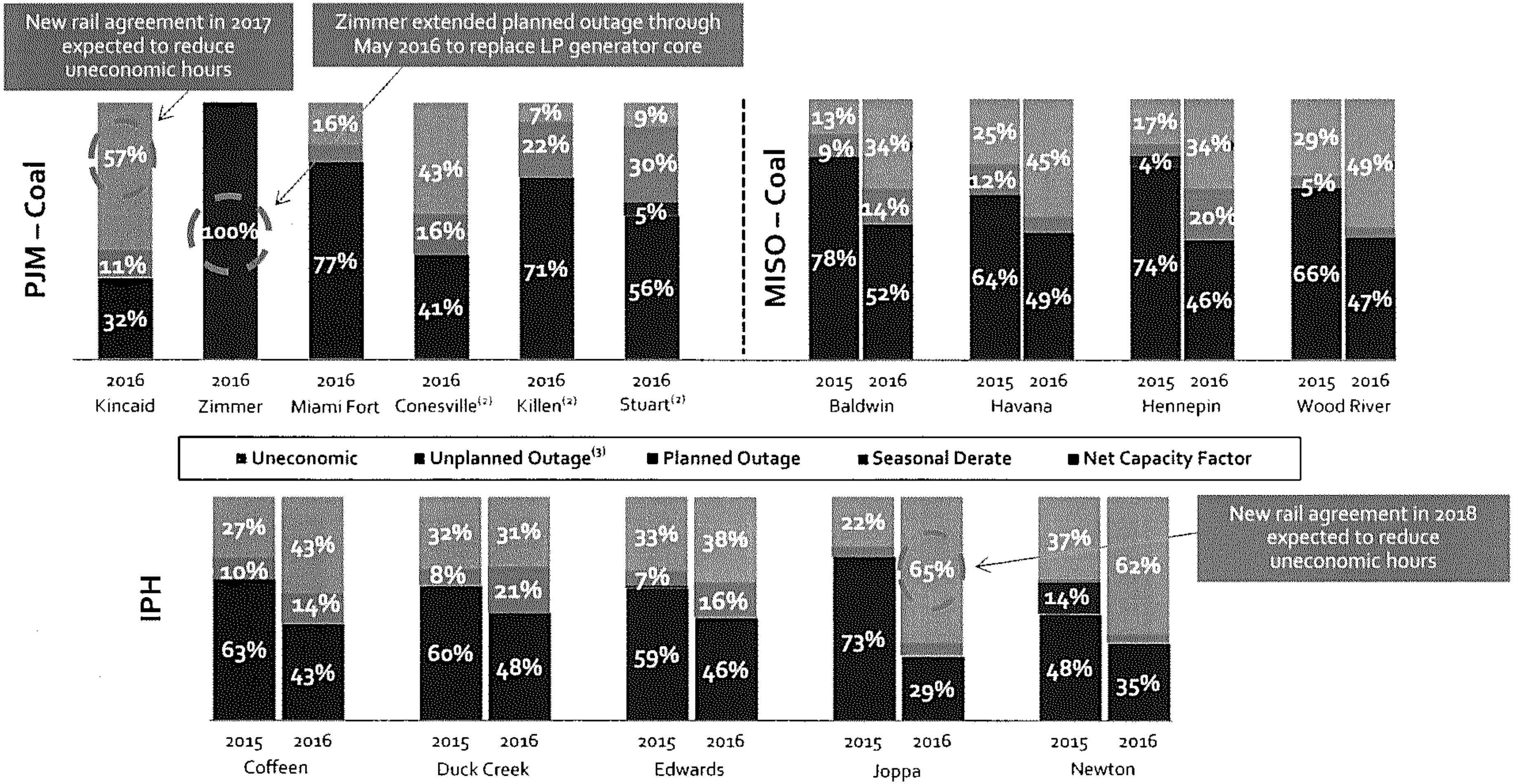
Exceptional reliability and unrivaled access to low cost fuel continues to lead to strong performance from the PJM gas assets

[1] Net Capacity Factor is based on the NERC method of calculation, which uses a maximum capacity rating; [2] A portion of Unplanned outages are related to maintenance work performed during uneconomic periods

DYNEGY

1Q16 Fleet Performance – Coal & IPH Segments

Net Capacity Factors[1]



Mild winter weather led to weak prices and lower capacity factors

[1] Net Capacity Factor is based on the NERC method of calculation, which uses a maximum capacity rating; [2] Jointly owned facilities not operated by Dynegy; [3] A Portion of Unplanned outages are related to maintenance work performed during uneconomic periods

DYNEGY

Operational Statistics

Coal Segment[1]	1Q15	1Q16
Total Generation (MM MWh)		
MISO	4.8	3.3
PJM	N/A	3.5
Brayton Point	N/A	0.8
In-Market-Availability		
MISO	91.3%	89.3%
PJM	N/A	76.6%
Brayton Point	N/A	91.8%
Average Capacity Factor[2]		
MISO	73.5%	50.4%
PJM	N/A	42.6%
Brayton Point	N/A	24.0%

IPH[1]	1Q15	1Q16
Total Generation (MM MWh)	5.2	3.3
In-Market-Availability	93.0%	86.1%
Average Capacity Factor[2]	59.9%	38.5%

[1] In-Market Availability and Average Capacity Factor do not include CTs; [2] Average Capacity Factor is based on the NERC method of calculation, which uses a maximum capacity rating

DYNEGY

Operational Statistics, cont.

Gas Segment - Combined Cycle	1Q15	1Q16
Total Generation (MM MWh)		
California	0.4	0.7
NY/NE	2.0	3.1
PJM	2.6	9.4
In-Market-Availability		
California	98.4%	98.9%
NY/NE	99.9%	88.8%
PJM	98.3%	97.5%
Average Capacity Factor[1]		
California	19.3%	29.3%
NY/NE	58.1%	39.9%
PJM	67.6%	83.0%

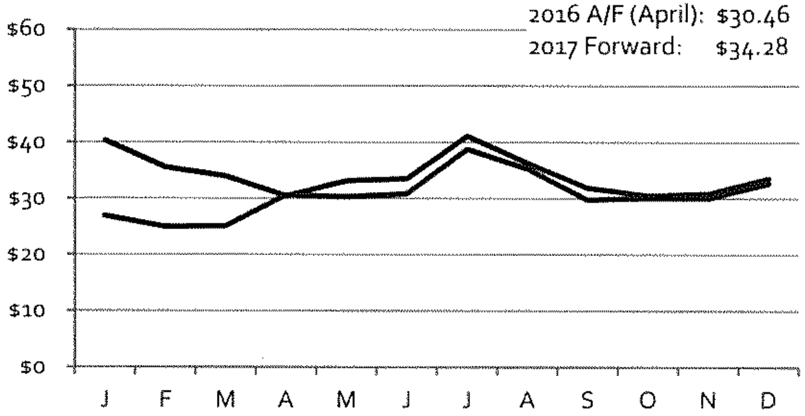
[1] Average Capacity Factor is based on the NERC method of calculation, which uses a maximum capacity rating

DYNEGY

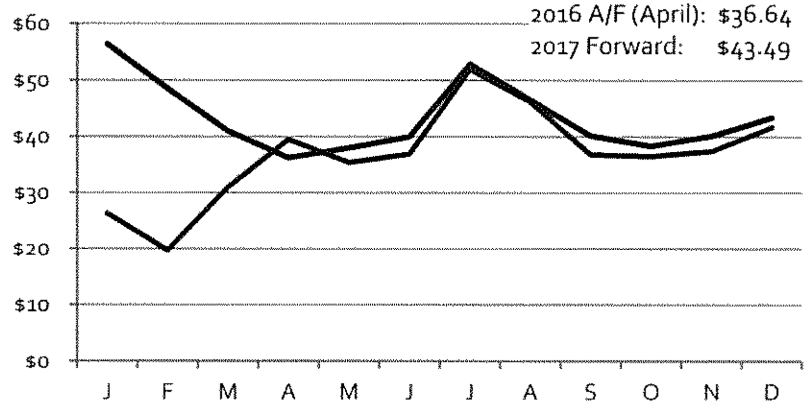
Commodity Pricing (on-peak power)

2016 A/F (Apr)[1] 2017 Forward

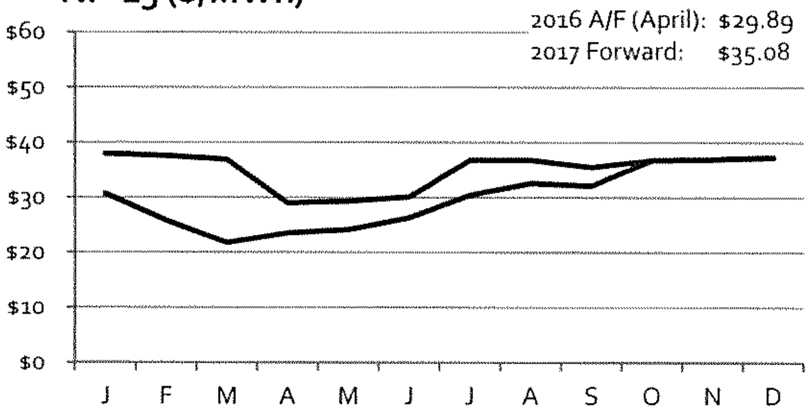
Indiana Hub ($/MWh)



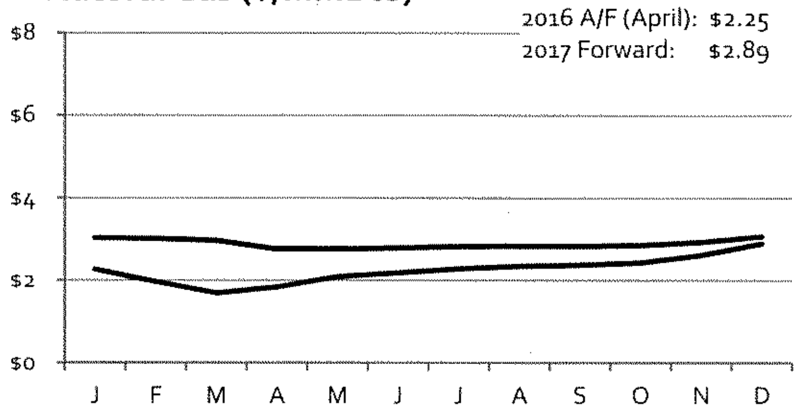
New York Zone A ($/MWh)



NP-15 ($/MWh)



Natural Gas ($/MMBtu)



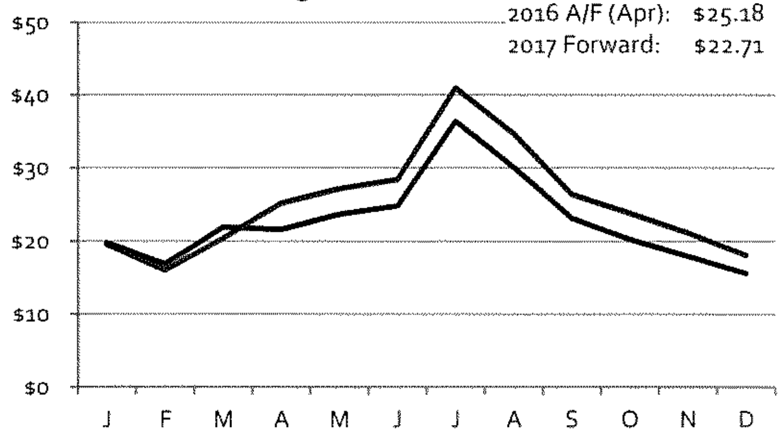
[1] Prices reflect actual day ahead on-peak settlement prices for 1/1/2016-4/19/2016 and quoted forward on-peak monthly prices for 4/20/2016-12/31/2016

DYNEGY

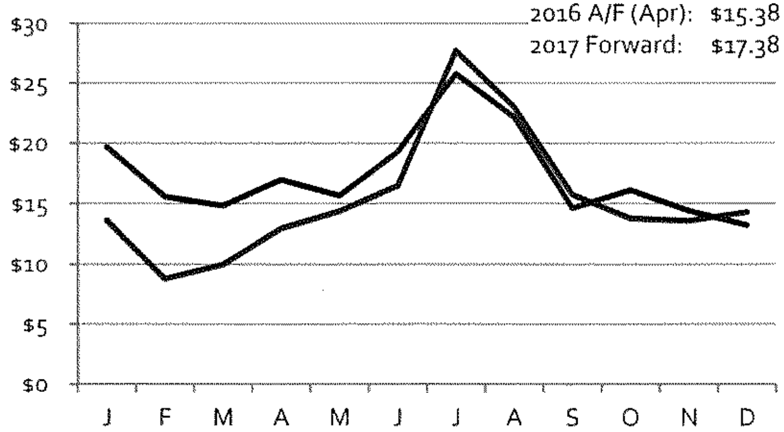
Spark Spreads (on-peak)

2016 A/F (Apr)[1] — 2017 Forward

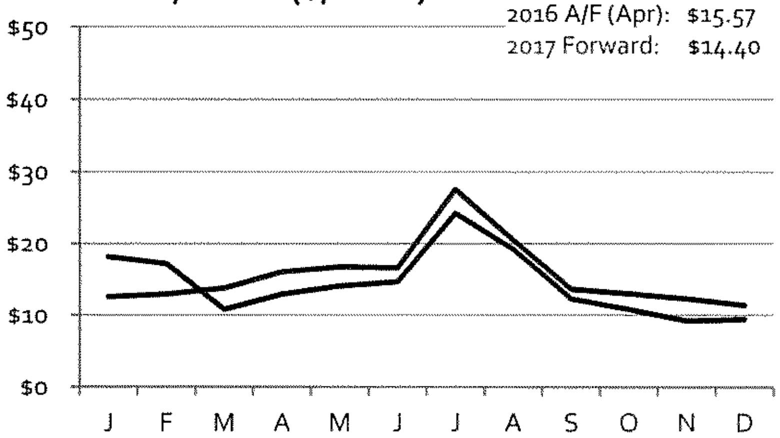
PJM West/TetM3 ($/MWh)



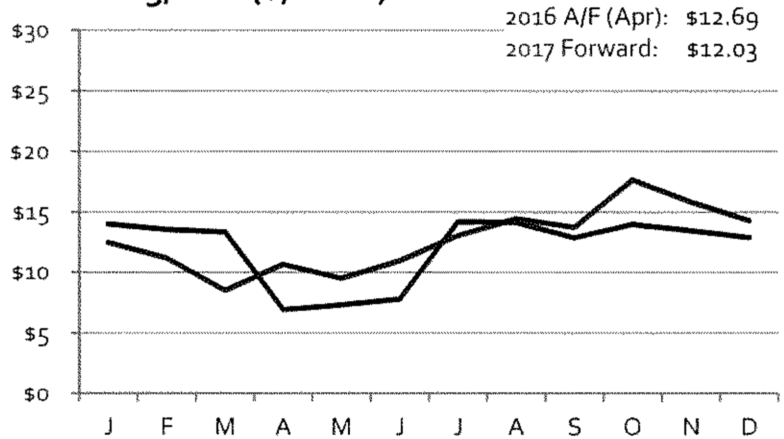
Mass Hub/Algonquin ($/MWh)



NI Hub/ChiCG ($/MWh)



NP-15/PGE ($/MWh)



[1] Prices reflect actual day ahead on-peak settlement prices for 1/1/2016-4/19/2016 and quoted forward on-peak monthly prices for 4/20/2016-12/31/2016

DYNEGY

Market Pricing

Average Actual Power/Gas Prices ($/MWh)

	1Q15		1Q16	
	On-Peak	Off-Peak	On-Peak	Off-Peak
Henry Hub ($/MMBtu)	$2.87		$1.98	
Indy Hub	$39.27	$28.97	$25.61	$20.18
Mass Hub	$96.19	$76.43	$33.85	$26.21
NP-15	$33.98	$28.55	$26.09	$21.40
NY - Zone A	$53.94	$39.46	$25.67	$13.89
PJM-W	$60.23	$43.66	$31.49	$25.59
AD Hub	$45.26	$32.27	$28.80	$22.92
NiHub	$40.82	$27.85	$27.35	$20.55

Average Trading Hub Spark Spreads ($/MWh)

	1Q15		1Q16	
	On-Peak	Off-Peak	On-Peak	Off-Peak
PJM West/TetM3	$17.55	$0.98	$18.72	$12.81
NiHub/ChiCG	$17.68	$4.71	$13.06	$6.26
NP-15/PGE	$12.67	$7.25	$10.72	$6.03
NY-Zone A/Dominion	$39.80	$25.32	$16.70	$4.92
Mass Hub/Algonquin	$14.92	-$4.84	$10.83	$3.19
AD Hub/Dominion	$31.12	$18.13	$19.83	$13.95

DYNEGY

MISO Capacity Position

Price in $/kw-mo	Coal Segment	IPH	Total	EBITDA Contribution
PY 15/16				
MWs	516	2,922	3,438	
Average Price	$4.00	$2.29	$2.55	$105 MM
PY 16/17				
MWs	1,003	2,970	3,973	
Average Price	$2.75	$4.28	$3.90	$186 MM
PY 17/18				
MWs	579	2,643	3,222	
Average Price	$2.35	$4.54	$4.14	$160 MM
PY 18/19				
MWs	242	2,328	2,570	
Average Price	$2.68	$5.09	$4.87	$150 MM
PY 19/20				
MWs	185	470	655	
Average Price	$2.60	$5.61	$4.76	$37 MM
Total MWs	2,525	11,333	13,858	
Average Price	$2.90	$4.05	$3.84	$638 MM

Capacity Updates for PY 2016/2017

- MISO planning year 2016/2017 cleared at $72/MW-day with Dynegy clearing no incremental MW beyond its Wholesale/Retail obligations
- Removal of Wood River from open position
- Addition of Joppa CTs to open position
- Removal of Newton Unit 2, Baldwin Unit 1 and Baldwin Unit 3 from open position beginning planning year 2017/2018

Remaining Open Capacity Could Contribute to EBITDA Increase

- ~5.5 GW of MISO capacity remains available to sell for Planning year 2017/2018 – 2019/2020[1]

~45% of MISO capacity remains available for sale through PY 2019/2020[2]

[1] Load Serving Entities in MISO must have their capacity requirements met for Planning Year 2016/2017 by conclusion of the auction, so Planning Year 2017/2018 is the next period for which Load Serving Entities must procure capacity; [2] Assumes ~4,000MW per planning year over PY 2017/2018 – PY 2019/2020; Note: Includes PJM exports

PJM Capacity Position[1]

PJM Region	Planning Year	Average Price ($/MW-day)	MW Position	Average Price ($/MW-day)	MW Position
		Legacy/Base Product		Capacity Performance Product	
RTO[2]	2015-2016	$131.91	5,109		
	2016-2017	$81.50	1,214	$134.00	3,992
	2017-2018	$120.28	2,484	$151.50	2,735
	2018-2019	$149.98	1,734	$164.77	3,905
ComEd	2015-2016	$136.04	2,902		
	2016-2017	$66.98	708	$134.00	2,284
	2017-2018	$120.86	919	$151.50	2,261
	2018-2019	$200.21	0	$215.20	2,855
MAAC	2015-2016	$167.60	507		
	2016-2017	$119.10	453	$134.00	51
	2017-2018	$120.00	0	$151.50	508
	2018-2019	$149.98	0	$166.80	508
EMAAC	2015-2016	$167.43	535		
	2016-2017	$119.53	485	$134.00	53
	2017-2018	$120.00	8	$151.50	533
	2018-2019	$210.63	0	$225.42	532
ATSI	2015-2016	$427.98	296		
	2016-2017	$115.75	361	$134.00	0
	2017-2018	$121.65	374	$151.50	0
	2018-2019	$149.98	0	$164.80	195

[1] PJM capacity position represent volumes cleared and purchased in primary annual auctions, incremental auctions, and transitional auctions. Also includes bilateral transactions; [2] Includes imports to PJM from IPH-MISO

ISO-NE/NYISO/CAISO Capacity Positions

Capacity / Resource Adequacy

ISO/Region	Contract Type	Average Price	Size (MWs)	Tenor
ISO-NE[1]	ISO-NE Capacity Auction	$3.31/kw-Mo	3,738	June 2015 to May 2016
		$3.25/kw-Mo	3,663	June 2016 to May 2017
		$6.99/kw-Mo	2,181	June 2017 to May 2018
		$9.66/kw-Mo	2,148	June 2018 to May 2019
		$7.03/kw-Mo	2,240	June 2019 to May 2020
NYISO[2][3]	ICAP	$2.19/kw-Mo	1,124	Winter 2015/2016
		$3.38/kw-Mo	872	Summer 2016
		$2.57/kw-Mo	693	Winter 2016/2017
		$3.40/kw-Mo	818	Summer 2017
		$3.10/kw-Mo	380	Winter 2017/18
		$3.31/kw-Mo	340	Summer 2018
		$3.13/kw-Mo	185	Winter 2018/2019
		$3.20/kw-Mo	125	Summer 2019
CAISO[4]	RA Capacity		44	Avg Bilateral Sold Q1 2016
			91	Avg Bilateral Sold Q2 2016
			575	Avg Bilateral Sold Q3 2016
			69	Avg Bilateral Sold Q4 2016
			725	Avg Bilateral Sold Cal 2017
			400	Avg Bilateral Sold Cal 2018
			850	Avg Bilateral Sold Cal 2019

[1] ISO-NE represents capacity auctions results, supplemental auctions and bilateral capacity sales; [2] NYISO represents capacity auction results and bilateral capacity sales; [3] Winter period covers November through April and the Summer period covers May through October; [4] Dynegy is prohibited from disclosing RA capacity sales through 2016 at Moss Landing 6&7

Appendix
Reg G Reconciliations

DYNEGY

Reg G Reconciliation – 1st Quarter 2015 Adjusted EBITDA

DYNEGY INC.
REPORTED SEGMENTED RESULTS OF OPERATIONS
THREE MONTHS ENDED MARCH 31, 2015
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the three months ended March 31, 2015:

	Three Months Ended March 31, 2015				
	Coal	IPH	Gas	Other	Total
Net loss attributable to Dynegy Inc.					$ (180)
Plus / (Less):					
Loss attributable to noncontrolling interest					(1)
Interest expense					136
Depreciation expense					64
Amortization expense					(4)
EBITDA (1)	$ 16	$ 29	$ 95	$ (125)	$ 15
Plus / (Less):					
Acquisition and integration costs	—	—	—	90	90
Loss attributable to noncontrolling interest	—	1	—	—	1
Mark-to-market adjustments	(7)	(11)	(13)	—	(31)
Change in fair value of common stock warrants	—	—	—	5	5
ARO accretion expense	1	3	—	—	4
Other	—	—	—	1	1
Adjusted EBITDA (1)	$ 10	$ 22	$ 82	$ (29)	$ 85

(1) EBITDA and Adjusted EBITDA are non-GAAP financial measures. Please refer to Item 2.02 of our Form 8-K filed on May 3, 2016, for definitions, utility and uses of such non-GAAP financial measures. A reconciliation of EBITDA to Operating income (loss) is presented below. Management does not allocate interest expense and income taxes on a segment level and therefore uses Operating income (loss) as the most directly comparable GAAP measure.

	Three Months Ended March 31, 2015				
	Coal	IPH	Gas	Other	Total
Operating income (loss)	$ 7	$ 22	$ 52	$ (121)	$ (40)
Depreciation expense	10	8	45	1	64
Amortization expense	(1)	(1)	(2)	—	(4)
Other items, net (1)	—	—	—	(5)	(5)
EBITDA	$ 16	$ 29	$ 95	$ (125)	$ 15

(1) Other items, net primarily consists of the change in fair value of our common stock warrants.

DYNEGY

Reg G Reconciliation – 1st Quarter 2016 Adjusted EBITDA

DYNEGY INC.
REPORTED SEGMENTED RESULTS OF OPERATIONS
THREE MONTHS ENDED MARCH 31, 2016
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the three months ended March 31, 2016:

	Three Months Ended March 31, 2016				
	Coal	**IPH**	**Gas**	**Other**	**Total**
Net loss attributable to Dynegy Inc.					$ (10)
Plus / (Less):					
Income tax expense					16
Interest expense					142
Depreciation expense					171
Amortization expense					14
EBITDA (1)	$ 81	$ 22	$ 271	$ (41)	$ 333
Plus / (Less):					
Earnings from unconsolidated investments	—	—	(2)	—	(2)
Cash distributions from unconsolidated investments	—	—	5	—	5
Acquisition and integration costs	—	—	—	4	4
Mark-to-market adjustments	(40)	(3)	(62)	—	(105)
Change in fair value of common stock warrants	—	—	—	(1)	(1)
ARO accretion expense	3	2	—	—	5
Wood River energy margin and O&M	5	—	—	—	5
Non-cash compensation expense	—	—	1	6	7
Other	1	—	(1)	—	—
Adjusted EBITDA (1)	$ 50	$ 21	$ 212	$ (32)	$ 251

(1) EBITDA and Adjusted EBITDA are non-GAAP financial measures. Please refer to Item 2.02 of our Form 8-K filed on May 3, 2016, for definitions, utility and uses of such non-GAAP financial measures. A reconciliation of EBITDA to Operating income (loss) is presented below. Management does not allocate interest expense and income taxes on a segment level and therefore uses Operating income (loss) as the most directly comparable GAAP measure.

	Three Months Ended March 31, 2016				
	Coal	**IPH**	**Gas**	**Other**	**Total**
Operating income (loss)	$ 54	$ 14	$ 120	$ (43)	$ 145
Depreciation expense	39	9	122	1	171
Amortization expense	(12)	(1)	27	—	14
Earnings from unconsolidated investments	—	—	2	—	2
Other items, net (1)	—	—	—	1	1
EBITDA	$ 81	$ 22	$ 271	$ (41)	$ 333

(1) Other items, net primarily consists of the change in fair value of our common stock warrants.

Reg G Reconciliation – Dynegy 2016 Adjusted EBITDA and Free Cash Flow Guidance

DYNEGY INC.
2016 ADJUSTED EBITDA AND FREE CASH FLOW GUIDANCE
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our 2016 Adjusted EBITDA guidance, updated based on April 19, 2016 forward curves, as presented on May 3, 2016:

	Dynegy Consolidated	
	Low	High
Net loss attributable to Dynegy Inc. (1)	$ (351)	$ (181)
Plus / (Less):		
Income tax expense (2)	16	16
Interest expense	540	545
Earnings from unconsolidated investments (2)	(2)	(2)
Operating Income	203	378
Depreciation expense	710	730
Amortization expense	30	30
Earnings from unconsolidated investments (2)	2	2
EBITDA (3)	945	1,140
Plus / (Less):		
Earnings from unconsolidated investments (2)	(2)	(2)
Acquisition and integration costs	35	40
Other (4)	22	22
Adjusted EBITDA (3)	$ 1,000	$ 1,200

(1) For purposes of Net loss attributable to Dynegy Inc. guidance reconciliation, mark-to-market adjustments and changes in the fair value of common stock warrants are assumed to be zero.

(2) Represents actual amounts for the three months ended March 31, 2016.

(3) EBITDA and Adjusted EBITDA are non-GAAP measures.

(4) Represents actual amounts for three months ended March 31, 2016. Other consists primarily of cash distributions from unconsolidated investments, asset retirement obligation accretion, non-cash compensation expense, and energy margin and operating and maintenance costs associated with our Wood River facility.

The following table provides summary financial data regarding our 2016 Free Cash Flow guidance:

	Dynegy Consolidated	
	Low	High
Adjusted EBITDA (1)	$ 1,000	$ 1,200
Cash interest payments	(515)	(515)
Acquisition and integration costs	(35)	(40)
Other cash items	10	10
Cash Flow from Operations	460	655
Maintenance capital expenditures	(275)	(275)
Environmental capital expenditures	(20)	(20)
Acquisition and integration costs	35	40
Free Cash Flow (1)	$ 200	$ 400

(1) Adjusted EBITDA and Free Cash Flow are non-GAAP measures.

Reg G Reconciliation – IPH 2016 Adjusted EBITDA Guidance

ILLINOIS POWER HOLDINGS (IPH)
2016 ADJUSTED EBITDA GUIDANCE
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our IPH 2016 Adjusted EBITDA guidance, based on April 19, 2016 forward curves, as presented on May 3, 2016:

Operating income	**$**	**61**
Depreciation expense		48
Amortization expense		(9)
Adjusted EBITDA (1)	**$**	**100**

(1) Adjusted EBITDA is a non-GAAP measure. Management does not allocate interest expense and income taxes on a segment level and therefore uses Operating Income (Loss) as the most directly comparable GAAP measure.

DYNEGY

Reg G Reconciliation – IPH 2015 Adjusted EBITDA and Free Cash Flow

IPH
ADJUSTED EBITDA AND FREE CASH FLOW
TWELVE MONTHS ENDED DECEMBER 31, 2015
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our IPH Adjusted EBITDA for the twelve months ended December 31, 2015:

Operating income	$	49
Depreciation expense		29
Amortization expense		(6)
EBITDA (1)		**72**
Loss attributable to noncontrolling interest		3
Mark-to-market adjustments		(10)
ARO accretion expense		12
Adjusted EBITDA (1)	$	77

(1) EBITDA and Adjusted EBITDA are non-GAAP financial measures. Please refer to Item 2.02 of our Form 8-K filed on May 3, 2016, for definitions, utility and uses of such non-GAAP financial measures. A reconciliation of EBITDA to Operating income is presented below. Management does not allocate interest expense and income taxes on a segment level and therefore uses Operating income as the most directly comparable GAAP measure.

The following table provides summary financial data regarding our IPH Free Cash Flow for the twelve months ended December 31, 2015:

Adjusted EBITDA (1)	$	77
Interest payments		(59)
Collateral		25
Working capital and other changes		(69)
Net cash used in operating activities		**(26)**
Maintenance capital expenditures		(28)
Environmental capital expenditures		(22)
Collateral		(25)
Working capital and other changes		69
Free Cash Flow (1)	$	(32)

(1) Adjusted EBITDA and Free Cash Flow are non-GAAP financial measures. Please refer to Item 2.02 of our Form 8-K filed on May 3, 2016, for definitions, utility and uses of such non-GAAP financial measures.

DYNEGY

Reg G Reconciliation – GENCO 2015 Adjusted EBITDA and Free Cash Flow

ILLINOIS POWER GENERATING COMPANY (GENCO)
ADJUSTED EBITDA AND FREE CASH FLOW
TWELVE MONTHS ENDED DECEMBER 31, 2015
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our Genco Adjusted EBITDA for the twelve months ended December 31, 2015:

Net loss attributable to Illinois Power Generating Company	**$**	**(562)**
Loss attributable to noncontrolling interest		(1)
Income tax benefit		(378)
Interest expense		39
Depreciation expense		86
EBITDA (1)		**(816)**
Loss attributable to noncontrolling interest		1
Impairments		855
ARO accretion expense		9
Adjusted EBITDA (1)	**$**	**49**

(1) EBITDA and Adjusted EBITDA are non-GAAP financial measures. Please refer to Item 2.02 of our Form 8-K filed on May 3, 2016, for definitions, utility and uses of such non-GAAP financial measures. A reconciliation of Adjusted EBITDA to Net loss attributable to Illinois Power Generating Company is presented above.

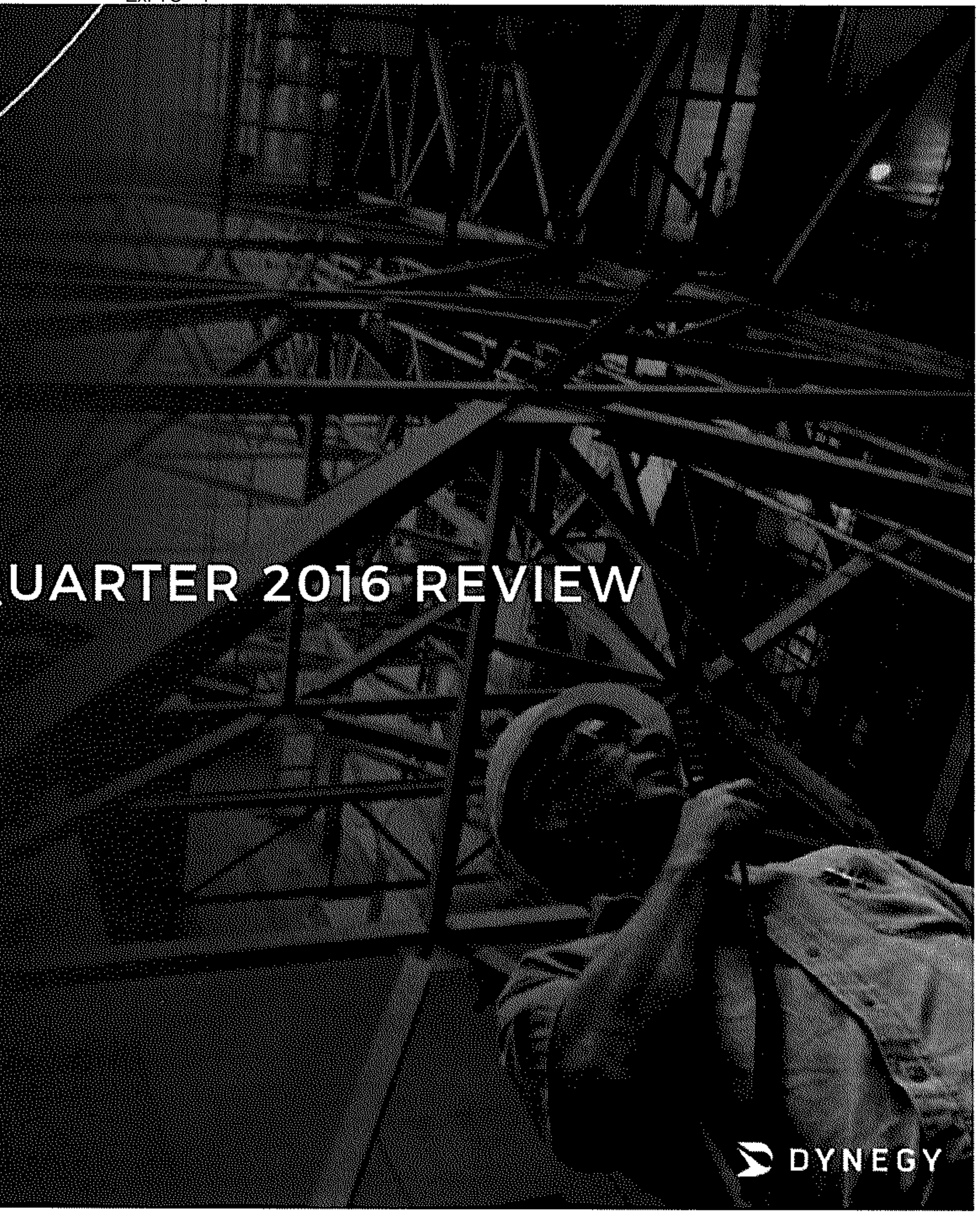
The following table provides summary financial data regarding our Genco Free Cash Flow for the twelve months ended December 31, 2015:

Adjusted EBITDA (1)	**$**	**49**
Interest payments		(59)
Working capital and other changes		3
Net cash used in operating activities		**(7)**
Maintenance capital expenditures		(17)
Environmental capital expenditures		(19)
Working capital and other changes		(3)
General and administrative expense		21
Free Cash Flow (1)	**$**	**(25)**

(1) Adjusted EBITDA and Free Cash Flow are non-GAAP financial measures. Please refer to Item 2.02 of our Form 8-K filed on May 3, 2016, for definitions, utility and uses of such non-GAAP financial measures.

DYNEGY

Ex. TC - 4



SECOND QUARTER 2016 REVIEW

AUGUST 3, 2016

DYNEGY

FORWARD-LOOKING STATEMENTS

Cautionary Statement Regarding Forward-Looking Statements

This presentation contains statements reflecting assumptions, expectations, projections, intentions or beliefs about future events that are intended as "forward looking statements." You can identify these statements by the fact that they do not relate strictly to historical or current facts. Management cautions that any or all of Dynegy's forward-looking statements may turn out to be wrong. Please read Dynegy's annual, quarterly and current reports filed under the Securities Exchange Act of 1934, including its 2015 Form 10-K and first and second quarter 2016 Forms 10-Q, when filed, for additional information about the risks, uncertainties and other factors affecting these forward-looking statements and Dynegy generally. Dynegy's actual future results may vary materially from those expressed or implied in any forward-looking statements. All of Dynegy's forward-looking statements, whether written or oral, are expressly qualified by these cautionary statements and any other cautionary statements that may accompany such forward-looking statements. In addition, Dynegy disclaims any obligation to update any forward-looking statements to reflect events or circumstances after the date hereof.

Non-GAAP Financial Measures

This presentation contains non-GAAP financial measures including EBITDA, Adjusted EBITDA and Free Cash Flow. Reconciliations of these measures to the most directly comparable GAAP financial measures to the extent available without unreasonable effort are contained herein. To the extent required, statements disclosing the definitions, utility and purposes of these measures are set forth in Item 2.02 to our current report on Form 8-K filed with the SEC on August 3, 2016, which is available on our website free of charge, www.dynegy.com.

TABLE OF CONTENTS

OVERVIEW AND OUTLOOK

2016 FINANCIAL PERFORMANCE

- 2Q16 Net Loss of $801 MM versus Net Income of $388 MM in 2Q15
- 2Q16 Adjusted EBITDA of $187 MM versus $193 MM in 2Q15
- Dynegy Inc. liquidity at 6/30/2016 of $2.2 billion

PORTFOLIO DEVELOPMENTS

- Dynegy to sell its 50% interest in Elwood for total cash proceeds of $172.5 MM; approximately $35 MM in previously posted collateral returned
- 9,804 MW of PY 19/20 PJM capacity cleared at an average price of $134/MW-day
- 500 MW of incremental MISO capacity approved for PJM pseudo-tie
- Completed 197 MW of uprates at five plants, exceeding target of 179 MW

ENGIE UPDATE

- Dynegy acquired ECP's 35% interest in the Atlas joint venture
- FERC only remaining regulatory approval required for closing
- ENGIE acquisition capital market financing complete
- Transaction remains on track for a 4Q16 closing

2016 OUTLOOK

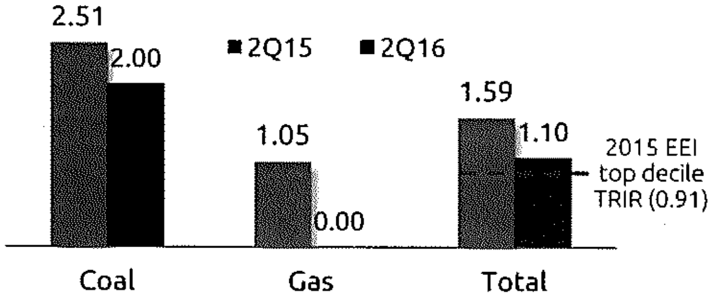
- 2016 Adjusted EBITDA guidance range narrowed to $1,000 - 1,100 MM
- 2016 Free Cash Flow guidance range narrowed to $200 - 300 MM
- 2016 segment hedges at 71% for Coal, 78% for IPH, and 68% for Gas
- 2016 PRIDE initiatives for Adjusted EBITDA remain on target; balance sheet PRIDE initiatives for 2016 expected to exceed target

SECOND QUARTER 2016 RESULTS

OPERATIONAL

Safety Performance

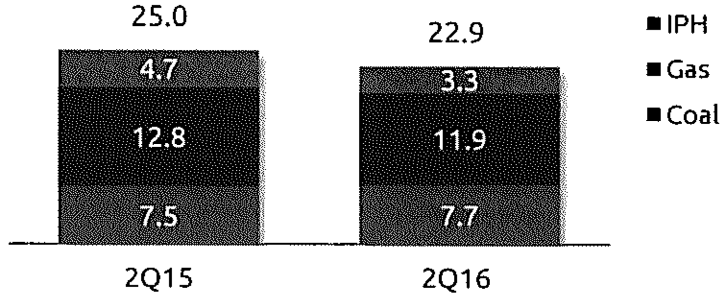
Total Recordable Incident Rate (TRIR)



- Gas fleet injury free in 2016, with the last recordable injury in August 2015
- Coal fleet improvement due to focused safety initiatives

Volumes Generated

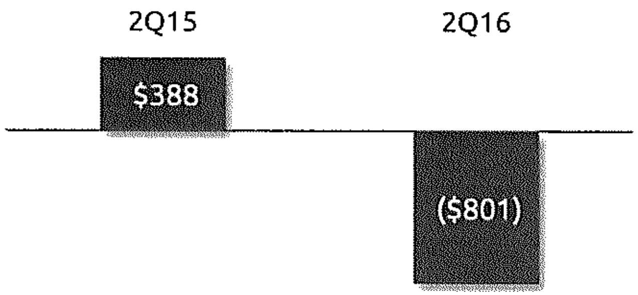
(MM MWh)



- IPH volumes decreased due to weaker pricing
- Gas segment volumes decreased due to an increase in planned major maintenance outages and lower spark spreads
- Coal segment volumes increased due to fewer outages and improved PJM reliability which were partially offset by weaker pricing

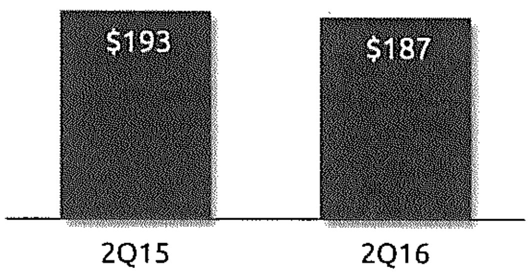
FINANCIAL

Net Income/(Loss) ($ MM)



- In 2Q16 an impairment charge of $645 MM was recorded associated with the Baldwin generating facility
- In 2Q15 Dynegy recognized a tax benefit of $480 MM due to the release of a deferred tax valuation allowance driven by the Duke and ECP transactions

Adjusted EBITDA ($ MM)

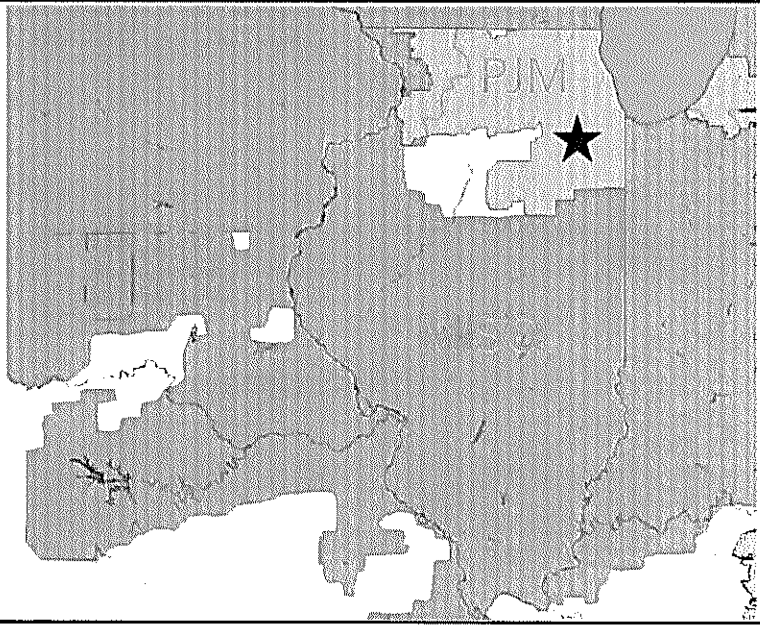


- Gas segment major maintenance outages in 2Q16 impacted gross margin and O&M expense
- Impact of Gas segment outages mostly offset by higher capacity revenues and lower coal fleet O&M

Note: Adjusted EBITDA and Free Cash Flow are non-GAAP measures; reconciliations to GAAP can be found in the Appendix

STRATEGIC DEVELOPMENT UPDATE – ELWOOD SALE

Elwood Energy Facility



MW Capacity (Summer Rating):	675 MW[1]
Ownership Percentage:	50%
ISO/Zone:	PJM/ComEd
Fuel/Type:	Natural Gas/CT (Peaker)
Heat Rate:	10,387
Operation Year:	1999

Transaction Summary

- Dynegy to sell its 50% interest in the Elwood Energy Facility for $172.5 MM
- Approximately $35 MM in previously posted collateral will be returned to Dynegy at closing
- Buyer will assume Dynegy's $76 MM share of non-recourse Elwood Sr. Notes
- Sale price of $368/kW based on a summer capacity rating[2]
- Expected annual Elwood Adjusted EBITDA contribution of $16 MM at Dynegy level

[1] Dynegy's ownership share; [2] Sale price calculation excludes returned collateral. (($172.5 MM sales price + $76 MM in assumed debt) / 675 MW summer capacity rating) * 1,000 = $368/kW

Proceeds from Elwood sale to be allocated to meet the ECP obligation

ENGIE ACQUISITION UPDATE

Regulatory

- April 2016 - Hart-Scott-Rodino early termination granted
- May 2016 – NY PSC issued Declaratory Order, no further review necessary
- July 8, 2016 – Responded to FERC letter requesting additional information
- July 20, 2016 – Received Texas PUC approval
- July 29, 2016 – One protest received that does not address the substance of our FERC filing

FERC approval is only remaining regulatory requirement

Financing

- Acquisition financing
  - $2 billion term loan, matures 2023; proceeds in escrow until closing
  - $460 MM issuance of tangible equity units
  - $198 MM from the monetization of PY 2017/2018 and PY 2018/2019 PJM capacity
- $125 MM in additional revolver capacity and a new LC facility at closing

Capital market financing complete

Integration

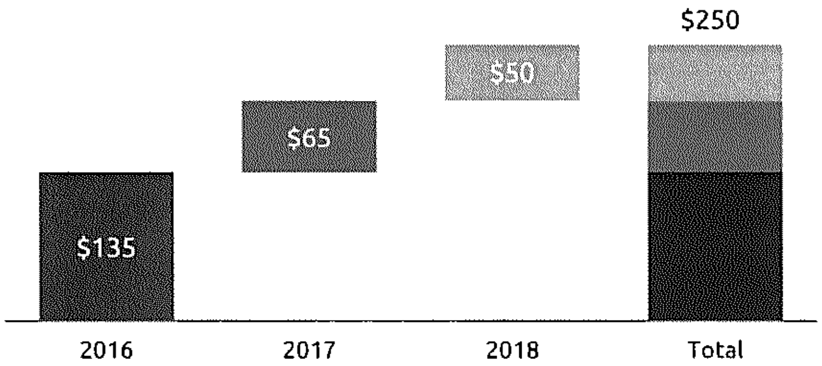
- Integration underway
- Synergies on track to exceed initial $90 MM target
- Synergy updates to be disclosed post-closing

Integration on target

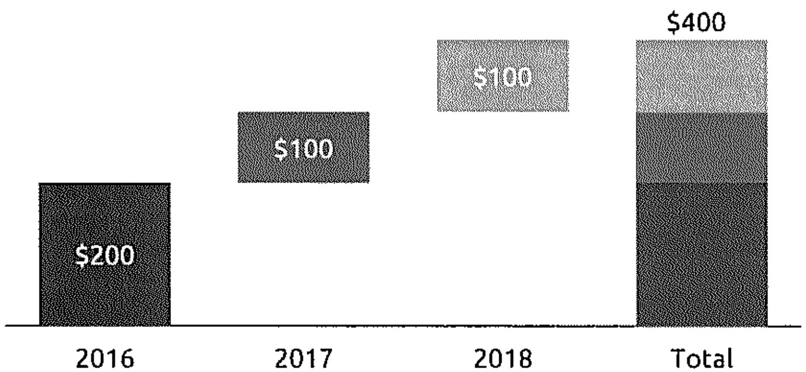
PRIDE ENERGIZED UPDATE

GOALS

2016 – 2018 PRIDE Energized EBITDA ($ MM)



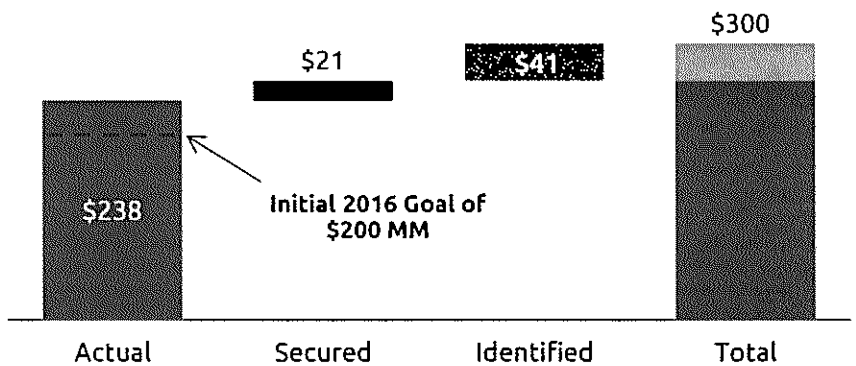
2016 – 2018 PRIDE Energized Balance Sheet ($ MM)



2016 PROGRESS

2016 PRIDE EBITDA Initiatives ($ MM)

2016 PRIDE Balance Sheet Initiatives ($ MM)



PRIDE Energized remains on track to meet EBITDA and exceed balance sheet targets for 2016

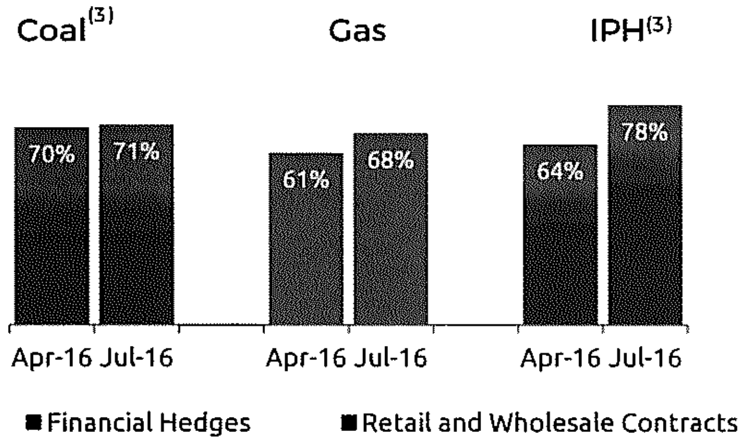
COMMERCIAL OVERVIEW

HANK JONES, CHIEF COMMERCIAL OFFICER

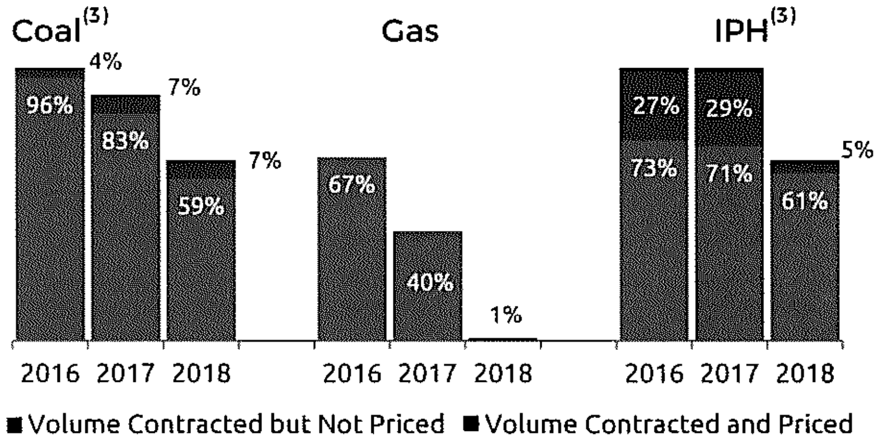
DYNEGY

COMMERCIAL UPDATE

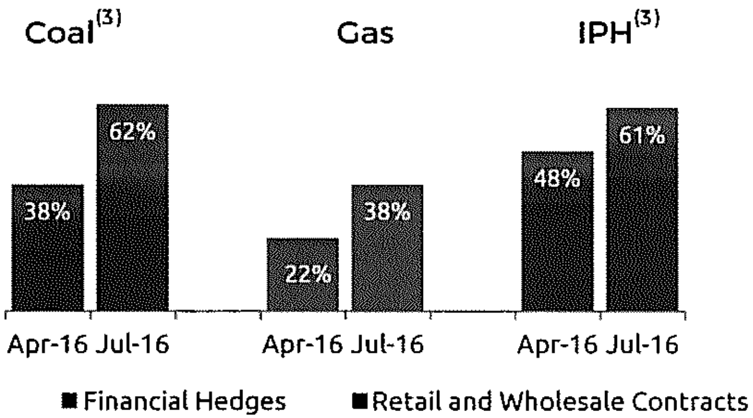
2016 Generation Volumes Hedged by Segment(1)



Fuel Supply Hedged by Segment(2)



2017 Generation Volumes Hedged by Segment(2)



Contracted Rail and Barge Transportation

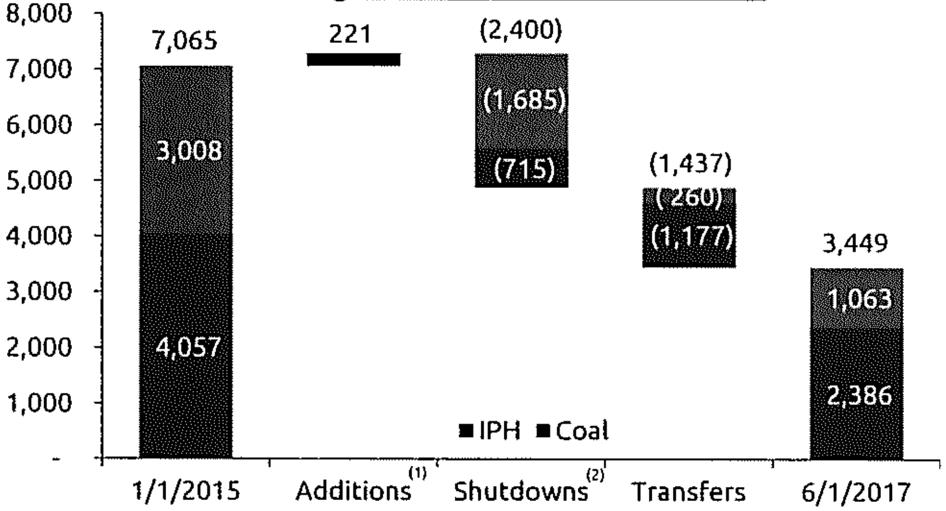
	2016	2017	2018-2020
Coal segment	100%	99%	54%
IPH	100%	100%	67%

- 2016 & 2017 Gas segment hedges lock in attractive spark spreads and remaining open position provides protection against declining gas prices
- IPH hedged by retail sales
- 2016 on-peak Coal segment ~78% hedged for balance of year
- 2017 hedge levels increase in Coal segment due to a combination of retail sales and financial hedges
- 2017 average around-the-clock hedge prices for the Coal segment are $1.50 and $3.50 per MWhr greater than 2016 prices at Indy and A/D Hub respectively

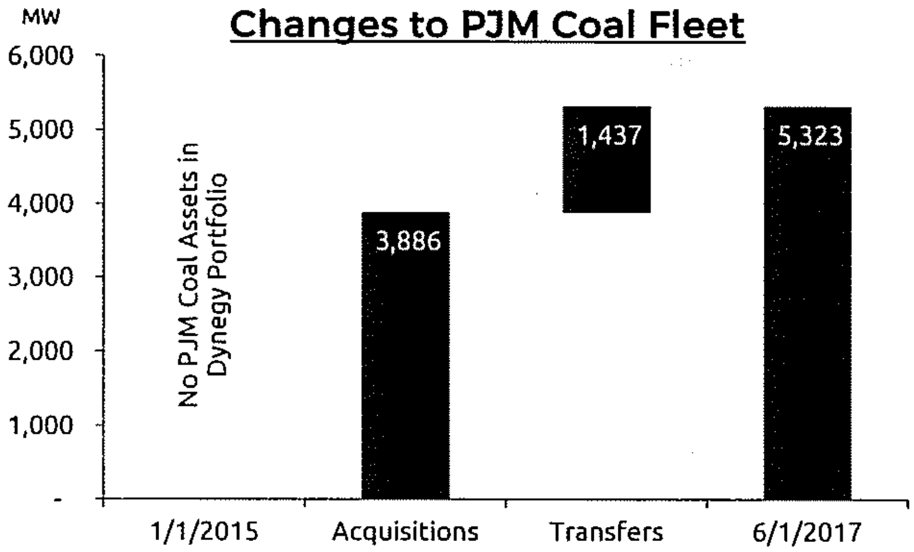
(1) Balance of the year as of 4/19/2016 and 7/14/2016; (2) As of 7/14/2016; (3) 2016 excludes Brayton Point and Newton Unit 2 as of Oct 2016, and Baldwin Unit 1 as of Nov 2016; 2017-2018 excludes Brayton Point, Baldwin Unit 1, Newton Unit 2, and Baldwin Unit 3 as of April 2017

COAL PORTFOLIO UPDATE

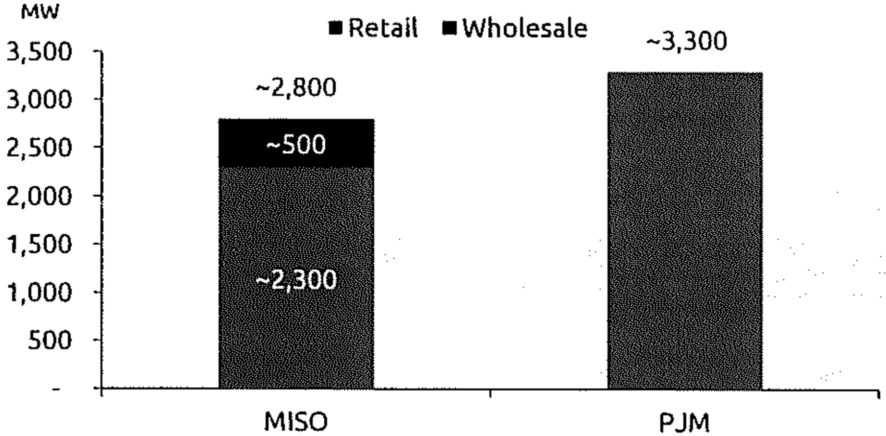
Changes to MISO Coal Fleet



Changes to PJM Coal Fleet



2017 Load Obligation Estimate



MISO Summary

- Wood River ceased operations June 1, 2016
- Newton Unit 2 shutdown status approved for September 15, 2016
- Baldwin Unit 1 shutdown status approved for October 17, 2016
- Baldwin Unit 3 plans to file for shutdown status in 3Q16
- By June 1, 2017 over 1,400 MW of Dynegy capacity located in MISO Zone 4 will be dedicated PJM resources via pseudo-ties
- Homefield Energy serves ~3.0 GW of load in Illinois (includes ~0.7 GW in ComEd)
- Dynegy Energy Services serves ~2.6 GW of load in Ohio and Illinois

(1) Previously mothballed MISO CTs , which are included in MISO's total MWs, brought back online in 2015; (2) Shutdowns include 100 MW at Edwards in 2015, 465 MW at Wood River in 2016, 615 MW at Newton Unit 2 in 2016, 590 MW at Baldwin Unit 1 in 2016, and 630 MW at Baldwin Unit 3 in 2017

Repositioning MISO coal assets to PJM

MISO ZONE 4 CAPACITY MARKET REDESIGN

Two Designs Under Consideration

Attribute	MISO FRA	Hybrid Prompt
Downward Sloping Demand Curve	✓	✓
Three Year Forward Auction	✓	X
Prompt Year Auction	X	✓
Incremental Auctions	X	(n/a)
MOPR Provisions	X	X
Regulated Utility Participation in Zone 4	✓	X
MISO Preference	✓	X
IMM Preference	X	✓

- MISO Expects to file with FERC in late August 2016 for an effective date prior to the next Planning Year (2017-2018)

Dynegy will continue to focus on other channels to market given the uncertainty in MISO market redesign

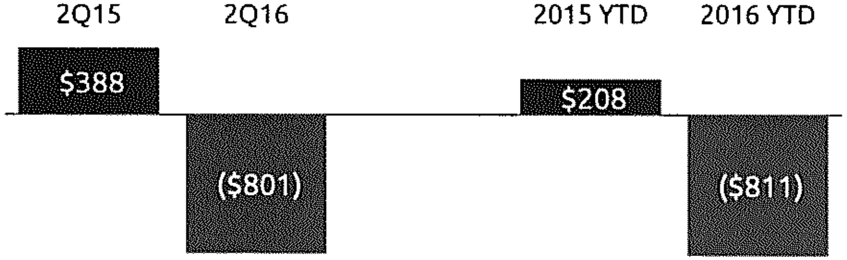
SECOND QUARTER 2016 FINANCIAL RESULTS

CLINT FREELAND, CHIEF FINANCIAL OFFICER

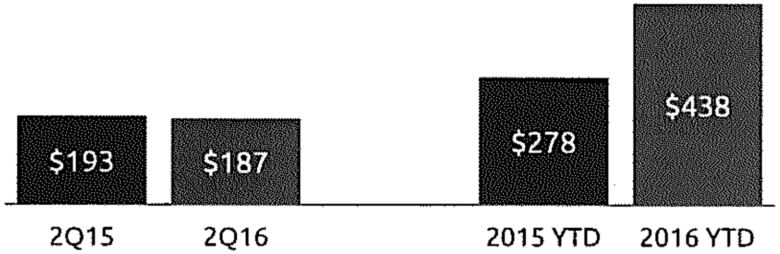
DYNEGY

FINANCIAL SUMMARY

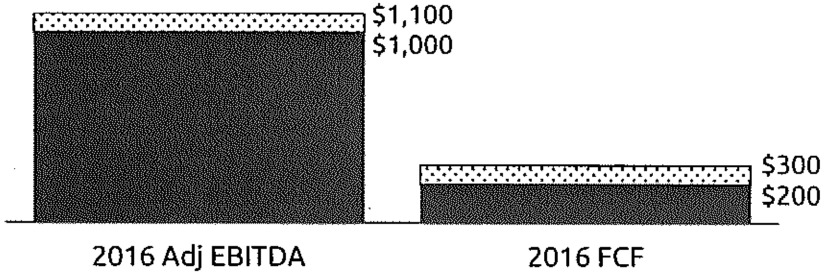
Net Income/(Loss) ($ MM)



Adjusted EBITDA Results ($ MM)



Guidance ($ MM)



Liquidity as of 6/30/2016 [1][2] ($ MM)

Unrestricted Cash at Dynegy Inc.	$1,066
Revolving Facilities & LC Availability at Dynegy Inc.	$1,093
Total Dynegy Inc. Liquidity (excluding IPH)	**$2,159**
Unrestricted Cash at IPH	$76
Revolver Facilities & LC Availability at IPH	$12
Total IPH Liquidity	**$88**

Financial Update

Adjusted EBITDA

- Gas segment results lower due to five major maintenance outages in 2Q16
- Coal segment and IPH capacity revenues and cost controls more than offset lower energy margins

Liquidity

- Total Dynegy Inc. liquidity includes net proceeds of TEU offering and monetization of previously cleared PJM capacity
- Dynegy Inc. liquidity excludes proceeds of $2 billion term loan issuance in 2Q16
- $125 MM in additional revolver capacity and a new LC facility at ENGIE closing

Guidance

- Narrowing 2016 Adjusted EBITDA Guidance from $1,000 - 1,200 MM to $1,000 - 1,100 MM
- Narrowing 2016 FCF guidance from $200 - 400 MM to $200 – 300 MM

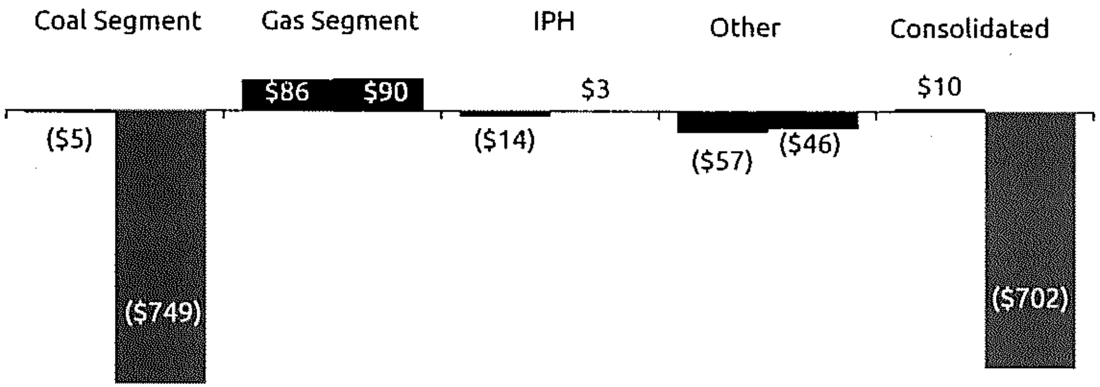
[1] See Appendix for additional detail. [2] Dynegy Inc. liquidity excludes $2 billion of restricted cash associated with acquisition financing
Note: Adjusted EBITDA and Free Cash Flow are non-GAAP measures; reconciliations to GAAP can be found in the Appendix

Ex. TC-4

SECOND QUARTER PERIOD-OVER-PERIOD SEGMENT PERFORMANCE

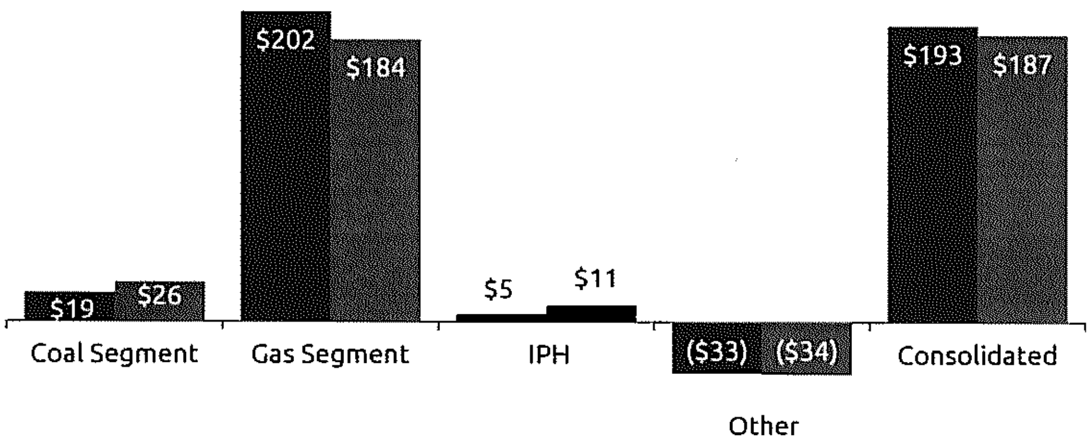
2Q Period-over-Period Operating Income/(Loss) ($ MM)

■2Q15 ■2Q16



2Q Period-over-Period Adjusted EBITDA ($ MM)

■2Q15 ■2Q16



Adjusted EBITDA Changes by Source

Coal Segment	
Energy Margin	($8) MM
Wholesale Capacity	$3 MM
O&M	$7 MM
Wood River Retirement	$6 MM
Gas Segment	
Energy Margin	($14) MM
Wholesale Capacity	$13 MM
O&M - Planned Major Maintenance Outages	($28) MM
Other	$12 MM
IPH	
Energy Margin	($12) MM
Wholesale Capacity	$12 MM
O&M	$11 MM
Other	($2) MM

Adjusted EBITDA relatively flat as lower energy margin and higher Gas segment O&M mostly offset by higher capacity revenues and lower coal fleet O&M

2016 GAS SEGMENT OUTAGES

2Q16 Gas Segment Major Maintenance Outages					
Facility	**Outage Days**	**Outage Scope**	**O&M Costs**	**Gross Margin Forgone**	**Amount of Uprate**
Ontelaunee	29 (GT1) & 25 (GT2)	Hot gas path inspection and uprates on both units	$5 MM	$4 MM	40 MW
Fayette	47 (GT1) & 47 (GT2)	Major inspection and uprates on both units	$6 MM	$6 MM	44 MW
Washington	31 (GT1) & 31 (GT2)	Major inspection and uprates on both units	$7 MM	$8 MM	47 MW
Independence	49 (GT3) & 56 (GT4)	Hot gas path inspection, major inspection, and uprates on both units	$6 MM	$1 MM	30 MW
Kendall	16 (GT2) & 51 (GT4)	Hot gas path Inspection and uprates on both units	$4 MM	$3 MM	36 MW
Total 2Q16	**382 outage days**		**$28 MM**	**$22 MM**	**197 MW**

4Q16 Scheduled Gas Segment Major Maintenance Outages					
Facility	**Outage Days**	**Outage Scope**	**O&M Costs**	**Gross Margin Forgone**	**Amount of Uprate**
Liberty	24 (GT2)	Major Inspection and uprate	$1 MM	$1 MM	16 MW
Independence	42 (GT1) & 42 (GT2)	Hot gas path inspection, major inspection, and uprates on both units	$5 MM	$2 MM	29 MW
Total 4Q16	**108 outage days**		**$6 MM**	**$3 MM**	**45 MW**

Nearly 200 MW of AGP uprates completed at a fraction of new build cost

Ex. TC-4

UPDATED 2016 ADJUSTED EBITDA AND FREE CASH FLOW GUIDANCE

Consolidated Dynegy Inc. ($ MM)	Updated	Previous[1]
Adjusted EBITDA	$1,000 – 1,100	$1,000 – 1,200
Maintenance CapEx	($275)	($275)
Recurring Environmental CapEx	($20)	($20)
Cash Interest	($515)	($515)
Other Cash Impacts	$10	$10
Free Cash Flow	$200 - 300	$200 - 400

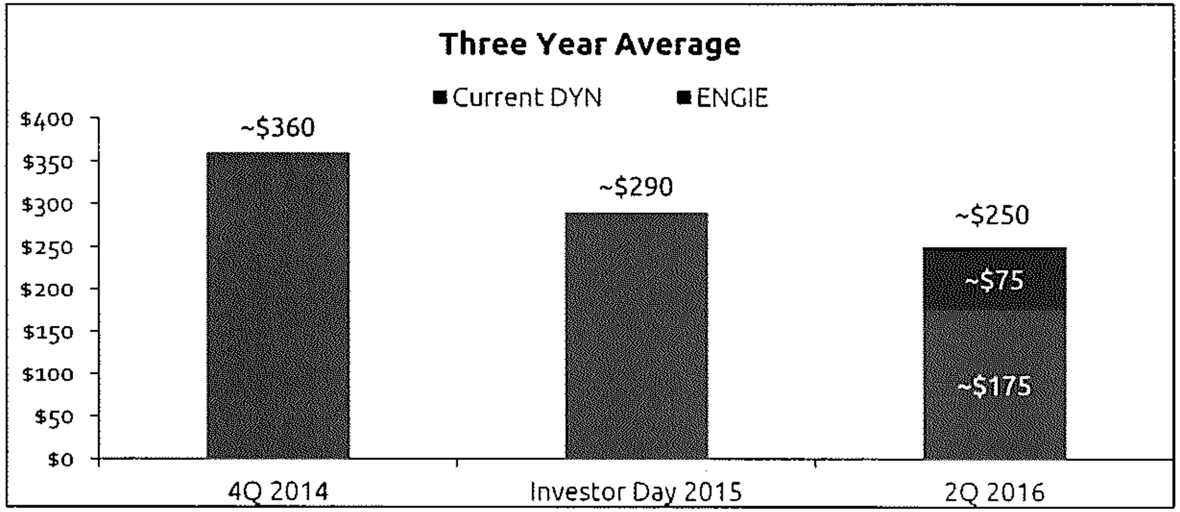
Guidance Update

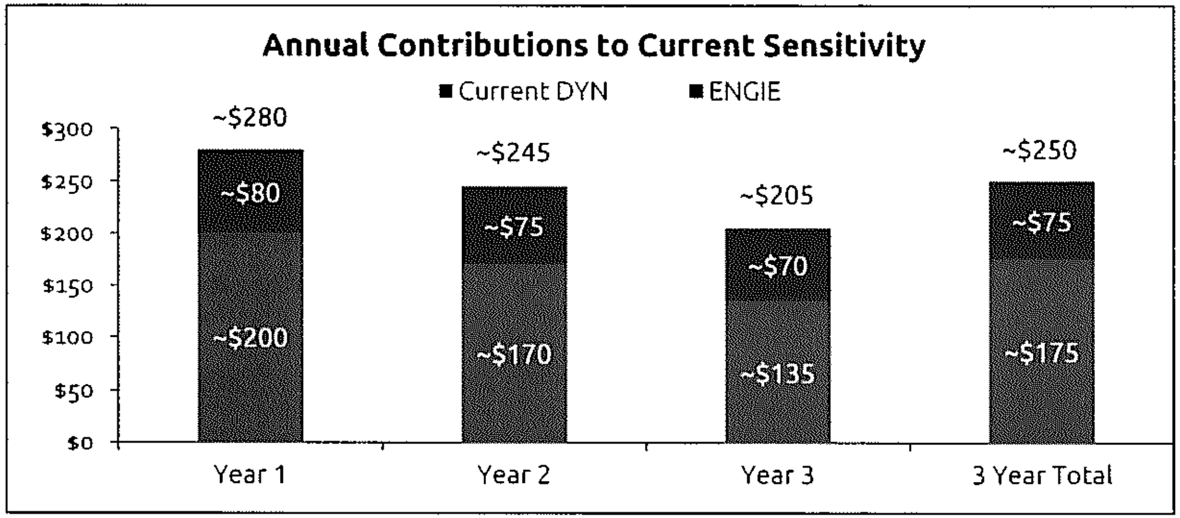
- Guidance update based on July 14, 2016 forward curves
- Forecast excludes Wood River
- IPH Adjusted EBITDA, before G&A allocations, estimated at $100 MM
- DI Capital Allocation (Excluded from Free Cash Flow)
  - $22 MM mandatory preferred dividends
  - $8 MM term loan amortization
  - $7 MM TEU debt service
  - $30 MM gas plant uprates
  - $50 MM of cash interest on ENGIE acquisition debt
  - $20 MM on OID of term loan debt
- IPH Capital Allocation (Excluded from Free Cash Flow)
  - $10 MM non-recurring environmental spend for the Newton scrubber and remediation work at Joppa

[1]As presented on February 24, 2016 and affirmed on May 3, 2016. Note: Adjusted EBITDA and Free Cash Flow are non-GAAP measures; reconciliations to GAAP can be found in the Appendix

ADJUSTED EBITDA SENSITIVITY

Impact of $1/MMBtu Natural Gas Price on Unhedged Adjusted EBITDA





Updated Sensitivity

- Reflects actual gas, power, and heat rate relationships implied in forward markets over the last three years
- Analysis utilizes current fleet, as adjusted for planned shutdowns

Current Dynegy Portfolio

- Decline in three year average driven primarily by:
  - Completed and scheduled asset shutdowns at Wood River, Baldwin, Newton, and Brayton Point
  - Meaningful declines in capacity factors at remaining coal fleet

ENGIE Portfolio

- Gas sensitivity driven by ERCOT assets
- Sensitivity stable over the last three years
- Addition of ENGIE fleet replaces a portion of sensitivity lost from coal portfolio changes

Sensitivity increases in a rising natural gas price environment and decreases as prices fall

SUMMARY

ROBERT C. FLEXON, PRESIDENT AND CEO

DYNEGY

KEY TAKEAWAYS

- ENGIE capital market financing complete; closing and integration on schedule
- Elwood sale provides over $200 MM in liquidity; to be allocated to purchase of ECP's 35% share in Atlas JV
- Added nearly 200 MW of low-cost uprates
- 500 MW of incremental MISO capacity transferred to PJM
- Adjusted EBITDA and FCF guidance range to $1,000 – 1,100 MM and $200 – 300 MM, respectively

APPENDIX

DYNEGY

DYNEGY GENERATION FACILITIES

Portfolio/Facility[1]	*Location*	*Net Capacity[2]*	*Primary Fuel*	*Dispatch Type*	*Market Region*
Coal Segment					
Baldwin[3]	Baldwin, IL	1,815	Coal	Baseload	MISO
Havana[4]	Havana, IL	434	Coal	Baseload	MISO
Hennepin[5]	Hennepin, IL	294	Coal	Baseload	MISO
Stuart*	Aberdeen, OH	904	Coal	Baseload	PJM
Miami Fort 7&8*	North Bend, OH	653	Coal	Baseload	PJM
Miami Fort CT	North Bend, OH	77	Oil – CT	Peaking	PJM
Zimmer*	Moscow, OH	628	Coal	Baseload	PJM
Conesville*	Conesville, OH	312	Coal	Baseload	PJM
Killen*	Manchester, OH	204	Coal	Baseload	PJM
Kincaid	Kincaid, IL	1,108	Coal	Baseload	PJM
Brayton Point	Somerset, MA	1,488	Coal	Baseload	ISO-NE
Coal Segment TOTAL		**7,917**			
IPH					
Coffeen	Coffeen, IL	915	Coal	Baseload	MISO/PJM
Joppa*[5][6]	Joppa, IL	802	Coal	Baseload	MISO
Joppa CT 1-3[6]	Joppa, IL	165	Gas – CT	Peaking	MISO
Joppa CT 4-5*[6]	Joppa, IL	56	Gas – CT	Peaking	MISO
Newton[3]	Newton, IL	1,230	Coal	Baseload	MISO/PJM
Duck Creek	Canton, IL	425	Coal	Baseload	MISO/PJM
E.D. Edwards	Bartonville, IL	585	Coal	Baseload	MISO/PJM
IPH TOTAL		**4,178**			

NOTES:

1) Dynegy owns 100% of each unit listed except for those marked by an asterisk (*). Total Net Capacity set forth in this table for partially owned units includes only Dynegy's proportionate share of that facility's gross generating capacity
2) Unit capabilities are based on winter capacity ratings
3) Capacity approved for shutdown included
4) Represents Unit 6 generating capacity
5) Portion of capacity scheduled to move to PJM beginning June 1, 2017
6) Not located within MISO

Assets in Multiple Markets
(Net Capacity by ISO)

	MISO	PJM
Coffeen	764	151
Newton	923	307
Duck Creek	96	329
Edwards	435	150

DYNEGY GENERATION FACILITIES, CONT.

Portfolio/Facility[1]	Location	Net Capacity[2]	Primary Fuel	Dispatch Type	Market Region
Gas Segment					
Casco Bay	Veazie, ME	538	Gas – CCGT	Intermediate	ISO-NE
Milford	Milford, CT	569	Gas – CCGT	Intermediate	ISO-NE
Lake Road	Dayville, CT	857	Gas – CCGT	Intermediate	ISO-NE
Dighton	Dighton, MA	185	Gas – CCGT	Intermediate	ISO-NE
Masspower	Indian Orchard, MA	280	Gas – CCGT	Intermediate	ISO-NE
Independence	Oswego, NY	1,156	Gas – CCGT	Intermediate	NYISO
Kendall	Minooka, IL	1,288	Gas – CCGT	Intermediate	PJM
Ontelaunee	Reading, PA	640	Gas – CCGT	Intermediate	PJM
Hanging Rock	Ironton, OH	1,430	Gas – CCGT	Intermediate	PJM
Washington	Beverly, OH	711	Gas – CCGT	Intermediate	PJM
Fayette	Masontown, PA	726	Gas – CCGT	Intermediate	PJM
Liberty	Eddystone, PA	589	Gas – CCGT	Intermediate	PJM
Dicks Creek	Monroe, OH	155	Gas – CT	Peaking	PJM
Lee	Dixon, IL	787	Gas – CT	Peaking	PJM
Elwood*	Elwood, IL	790	Gas – CT	Peaking	PJM
Richland	Defiance, OH	423	Gas – CT	Peaking	PJM
Stryker	Stryker, OH	16	Oil – CT	Peaking	PJM
Moss Landing	Moss Landing, CA				
Units 1-2		1,020	Gas – CCGT	Intermediate	CAISO
Units 6-7		1,509	Gas – CT	Peaking	CAISO
Oakland	Oakland, CA	165	Oil – CT	Peaking	CAISO
Gas Segment TOTAL		**13,834**			
TOTAL GENERATION		**25,929**			

NOTES:

1) Dynegy owns 100% of each unit listed except for those marked by an asterisk (*). Total Net Capacity set forth in this table for partially owned units includes only Dynegy's proportionate share of that facility's gross generating capacity

2) Unit capabilities are based on winter capacity ratings

DYNEGY, INC. DEBT & OTHER FINANCING OBLIGATIONS[1] ($ MM)

	12/31/2016 Estimate	12/31/2017 Estimate	12/31/2018 Estimate	12/31/2019 Estimate	3 Year Debt Reductions
Bank/Capital Market Debt:					
Senior Notes[2]	$5,600	$5,600	$5,600	$5,600	
Term Loan	2,772	2,744	2,716	2,688	
Revolving Facility	450	450	450	450	
Tangible Equity Units	73	45	16	-	
	$8,895	$8,839	$8,782	$8,738	($157)
Other Debt Obligations:					
Forward Capacity Agreement	$219	$155	$45	$-	
Emissions Inventory Financing	78	48	-	-	
Coal Inventory Financing	57	-	-	-	
Equipment Financing Agreement	84	64	54	38	
	$438	$267	$99	$38	($400)
Total[3]	**$9,333**	**$9,106**	**$8,881**	**$8,776**	**($557)**
Equity Financing:					
Tangible Equity Units	$373	$373	$373	$-	
Mandatory Converts	400	-	-	-	
	$773	$373	$373	$-	

Other Debt Obligations:

- Emissions Inventory Financing: Debt reduced as Dynegy procures emission credits in the normal course of business
- Coal Inventory Financing: Debt reduced as Brayton Point's coal inventory is burned in advance of retirement
- Equipment Financing: Repayments incorporated into LTSA payment schedule as debt balance is reduced when these payments are made

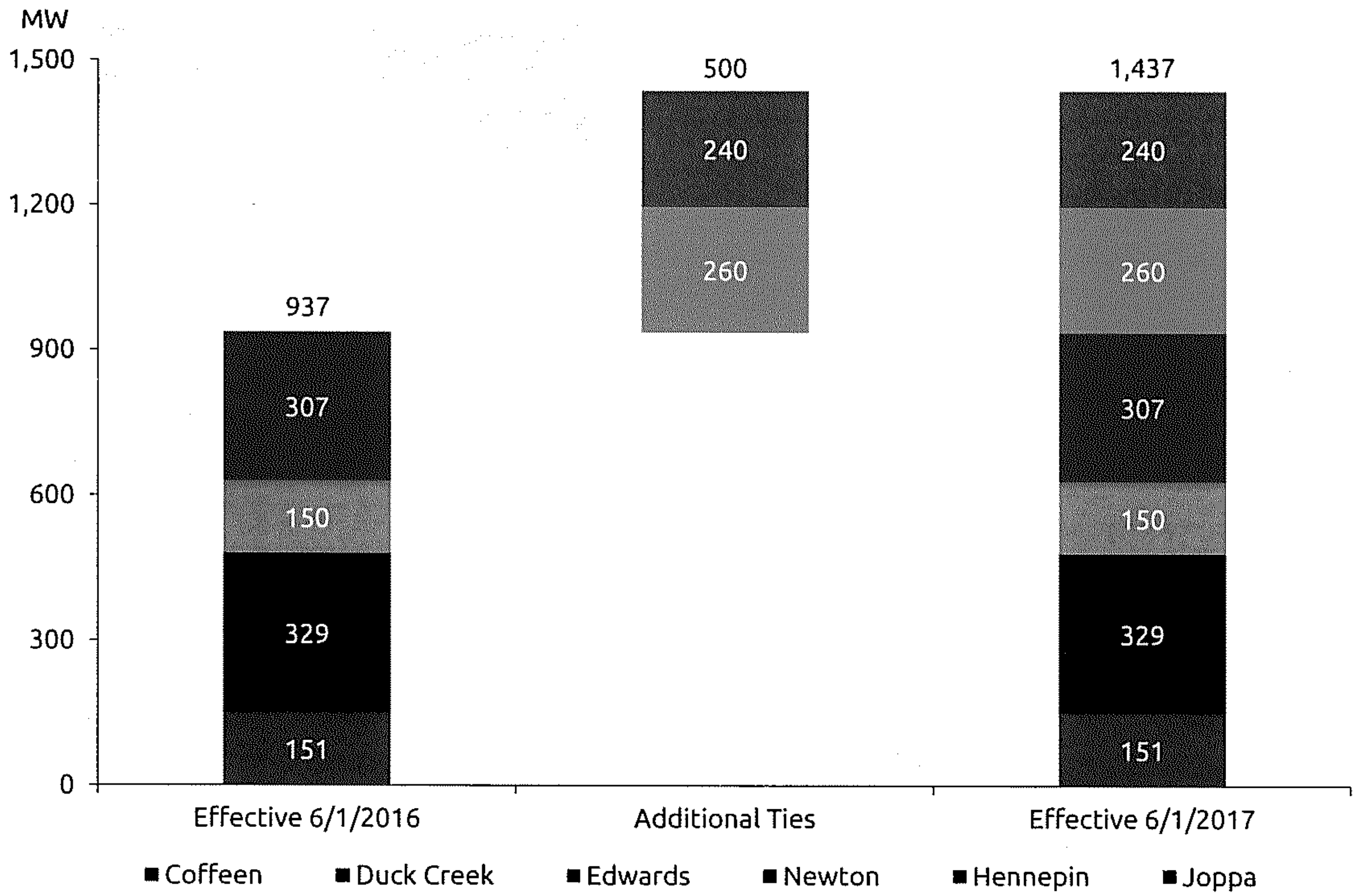
Equity Financing:

- Tangible Equity Units: Will convert to between 23 and 29 million shares of common stock on July 1, 2019. Forward equity sale reflected in shareholders' equity section of Dynegy's balance sheet
- Mandatory Converts: Will convert to between 10 and 13 million shares of common stock on November 1, 2017

(1)Excludes Genco Notes and any voluntary prepayments of debt
(2) Assumes refinancing of $2.1 billion note due in 2019
(3) Total excludes $375 MM ECP obligation - $172.5MM to be paid using Elwood sales proceeds

Including reduction in ECP obligation with proceeds from Elwood sale, over $700 MM in de-levering to occur by the end of 2019 before any voluntary debt repayments

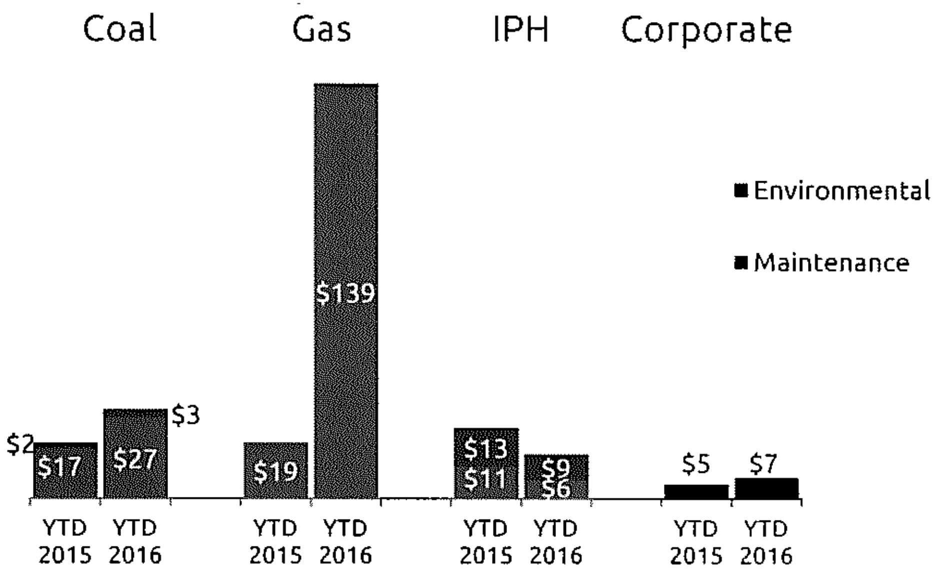
MISO PSEUDO-TIE SUMMARY



By June 1, 2017 over 1,400 MW of Dynegy capacity located in Zone 4 will be dedicated PJM resources via pseudo-ties

CAPITAL AND MAJOR MAINTENANCE O&M EXPENDITURES YEAR-OVER-YEAR

Capital Expenditures by Segment[1][2] ($ MM)



Coal Segment

- Capital spending increased primarily related to the complete generator replacement at Zimmer[3]

Gas Segment

- Capital spending increased due to a larger number of planned major outages

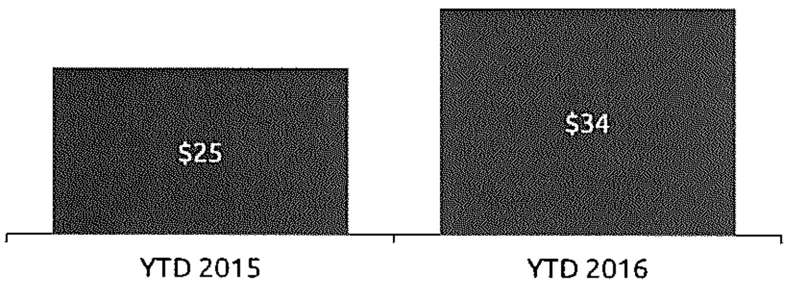
IPH

- Capital spending reduced due to fewer spring outages

Corporate

- Capital spending increased primarily due to office HQ expansion

Total Major Maintenance Expense ($ MM)



Coal, Gas, and IPH Segments

- Increase in maintenance expense mostly due to increased number of planned major outages in the Gas segment
- Major maintenance was partially offset within IPH segment with fewer spring outages

[1] Excludes capitalized interest; [2] Excludes discretionary investments for growth and reliability; [3] Costs associated with the Zimmer generator replacement offset by insurance proceeds received in 2016

DEBT, LIQUIDITY, AND RING-FENCING (as of 6/30/2016)

Dynegy Inc.[1]

$776 MM Term Loan
$500 MM of 5.875% Senior Notes
$2.1 BN in 6.75% Senior Notes
$1.75 BN in 7.375% Senior Notes
$1.25 BN in 7.625% Senior Notes
$87 MM in 7.00% Amortizing Notes (TEUs)

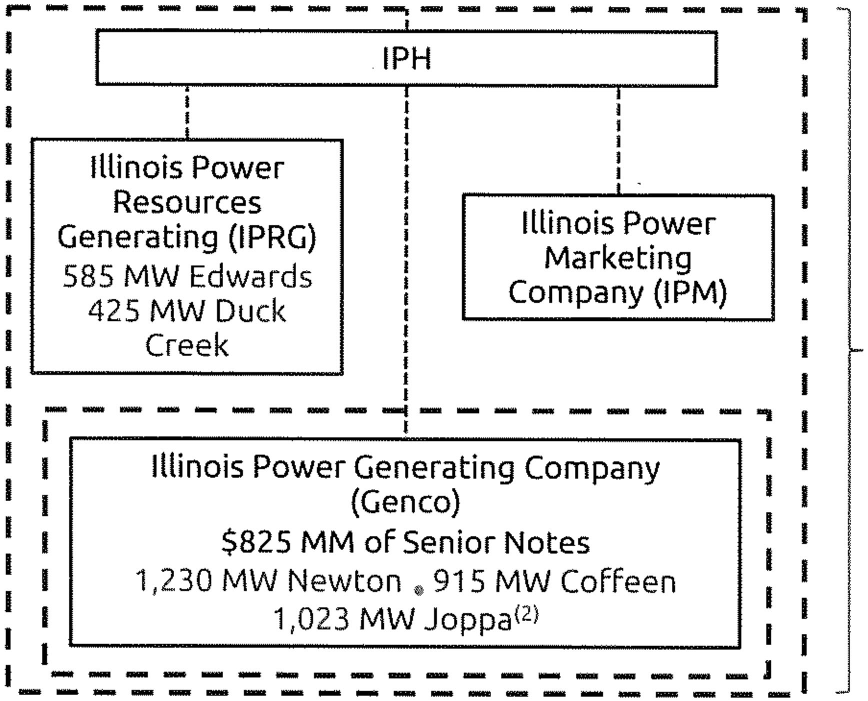
Dynegy Finance IV, Inc.

$2.0 BN Tranche C Term Loan

Available Liquidity ($ MM)

Cash and Equivalents	$1,066
Revolver & LC Capacity	*$1,480*
Outstanding LCs	*($387)*
Revolver Availability	$1,093
Total DI Liquidity	**$2,159**

Ring-fencing

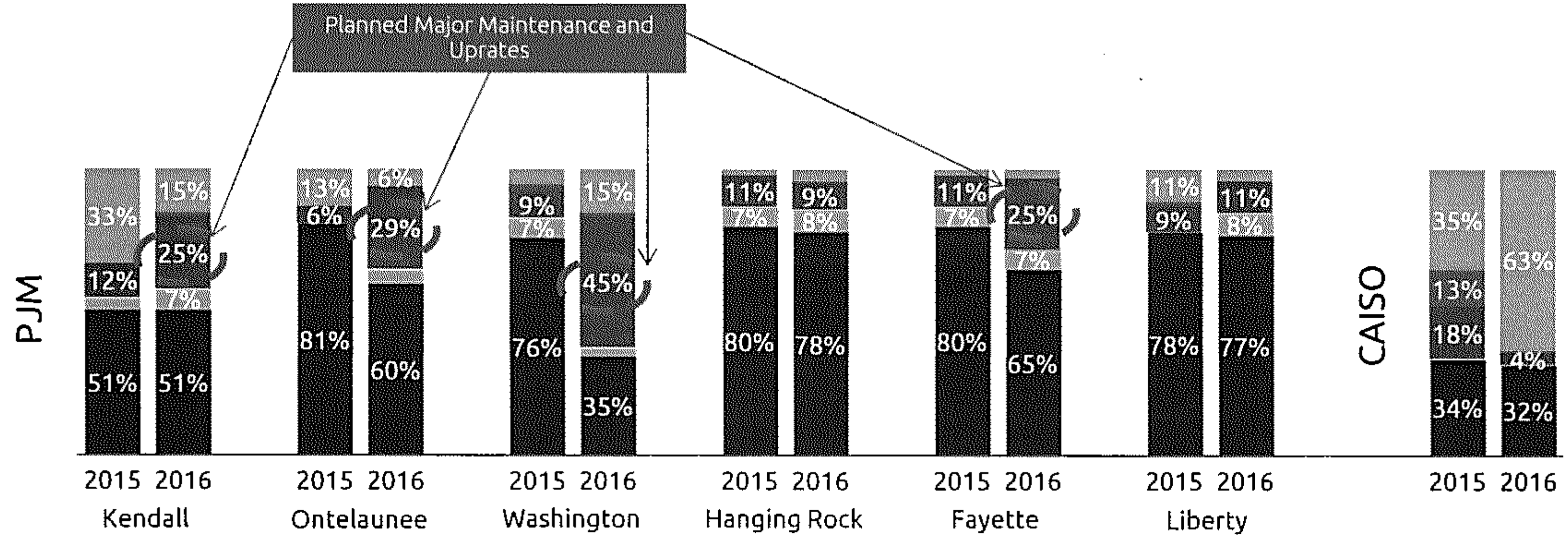


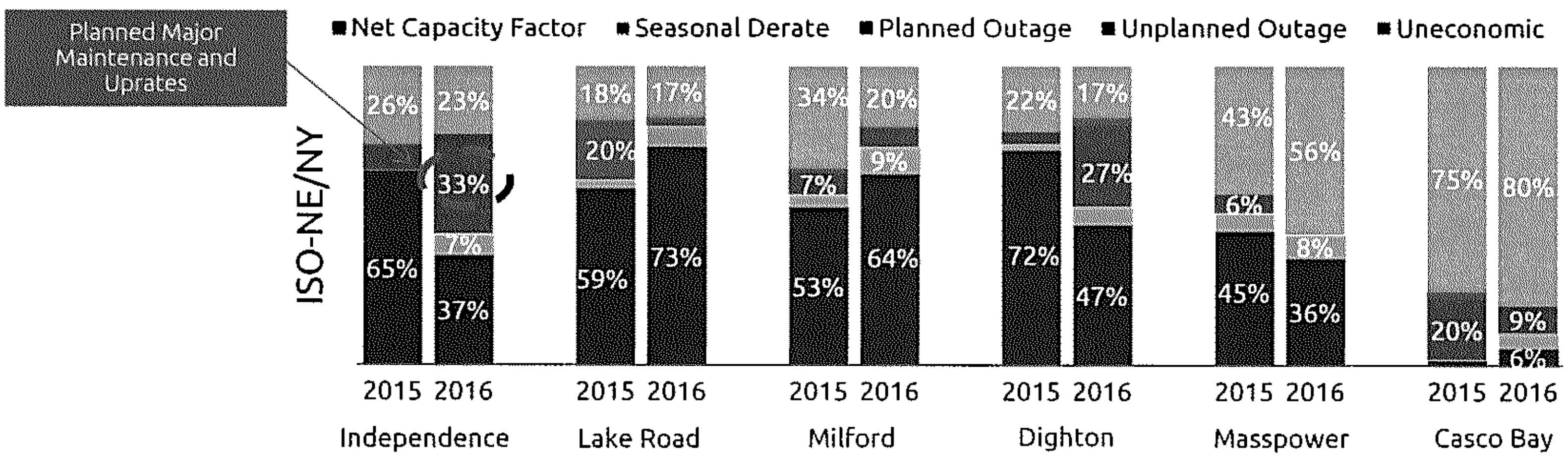
Cash and Equivalents[3]	$76
Revolver & LC Capacity	*$39*
Outstanding LCs	*($27)*
Revolver Availability	$12
Total IPH Liquidity	**$88**

[1] Excludes $76 MM of nonrecourse Elwood Senior Notes; [2] Reflects 80% stake; [3] Genco cash of $42 million

SECOND QUARTER FLEET PERFORMANCE – GAS SEGMENT

NET CAPACITY FACTORS(1)



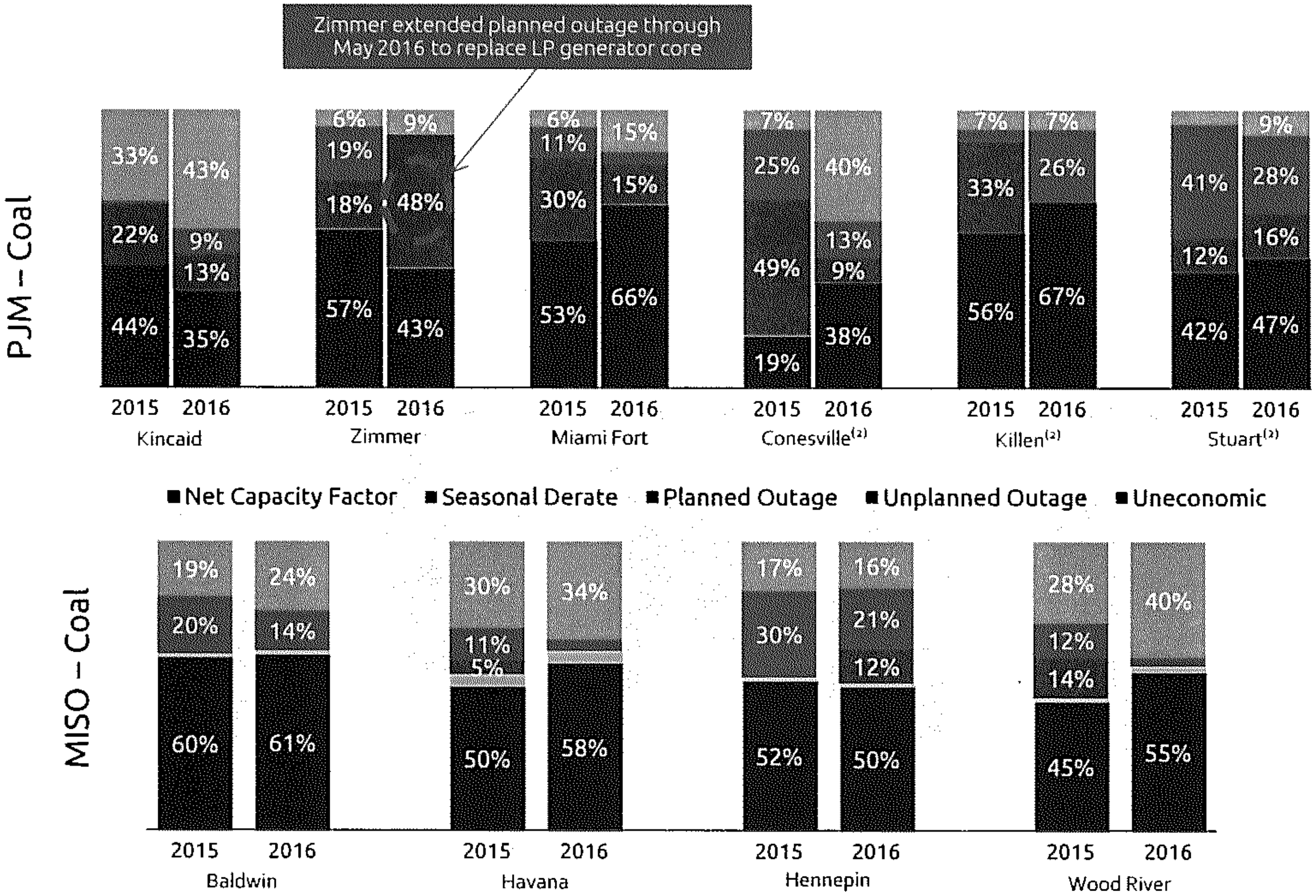


(1) Net Capacity Factor is based on the NERC method of calculation, which uses a maximum capacity rating

Performance uprates were opportunistically scheduled to coincide with major maintenance planned outages to minimize impact on plant availability

SECOND QUARTER FLEET PERFORMANCE – COAL SEGMENT

NET CAPACITY FACTORS[1]

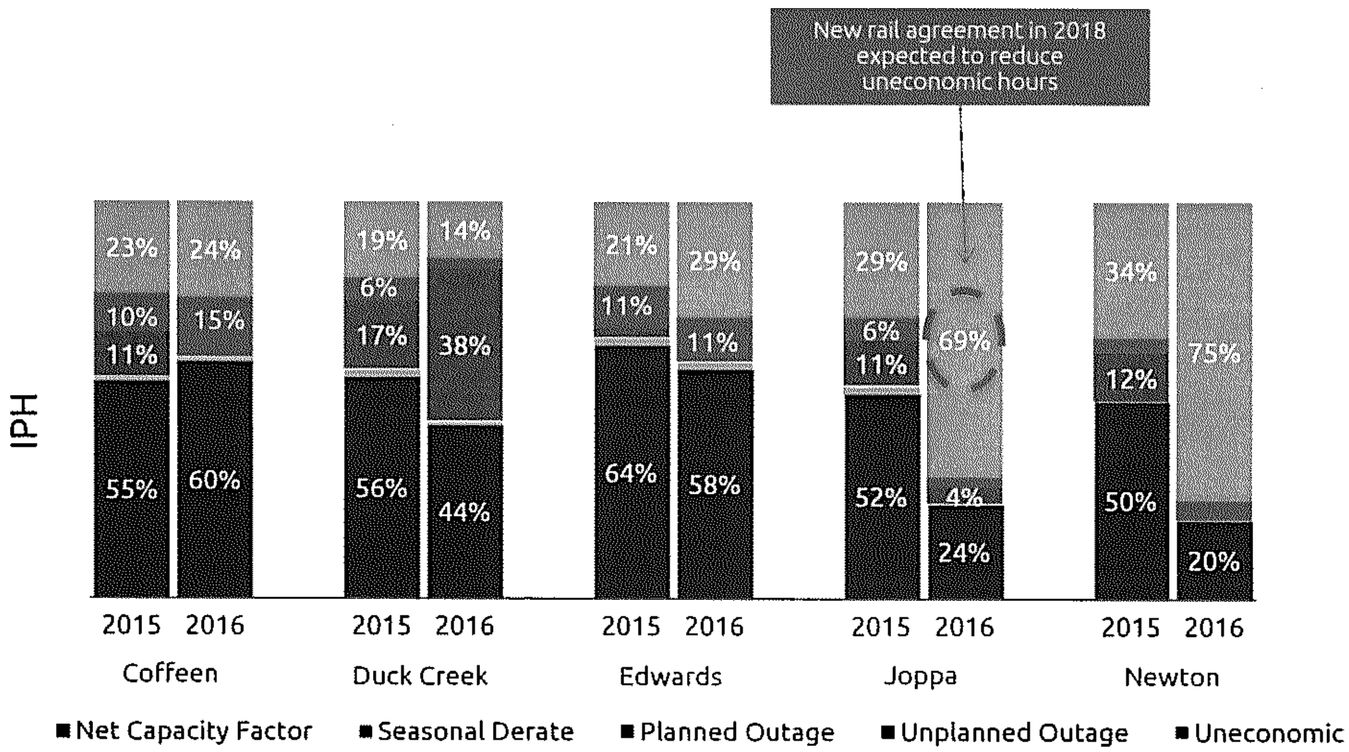


[1] Net Capacity Factor is based on the NERC method of calculation, which uses a maximum capacity rating; [2] Jointly owned facilities not operated by Dynegy

Low prices in MISO continue to negatively impact capacity factors

SECOND QUARTER FLEET PERFORMANCE – IPH SEGMENT

NET CAPACITY FACTORS[1]



[1] Net Capacity Factor is based on the NERC method of calculation, which uses a maximum capacity rating

Low prices in MISO continue to negatively impact capacity factors

OPERATIONAL STATISTICS

Coal Segment[1]	2Q15	2Q16	YTD 2015	YTD 2016
Total Generation (MM MWh)				
MISO	3.6	3.6	8.4	7.0
PJM	3.9	3.8	3.9	7.2
Brayton Point	0.1	0.3	0.1	1.1
In-Market-Availability				
MISO	75.9%	86.1%	85.6%	87.2%
PJM	69.9%	78.6%	69.9%	77.7%
Brayton Point	92.5%	95.0%	92.5%	93.0%
Average Capacity Factor[2]				
MISO	56.0%	58.5%	64.8%	54.3%
PJM	44.9%	46.3%	44.9%	44.4%
Brayton Point	1.8%	8.1%	1.8%	16.2%

IPH[1]	2Q15	2Q16	YTD 2015	YTD 2016
Total Generation (MM MWh)	4.7	3.3	9.9	6.6
In-Market-Availability	90.5%	90.7%	92.0%	89.5%
Average Capacity Factor[2]	53.6%	38.3%	56.4%	38.4%

[1] In-Market Availability and Average Capacity Factor do not include CTs; [2] Average Capacity Factor is based on the NERC method of calculation, which uses a maximum capacity rating

OPERATIONAL STATISTICS, CONT.

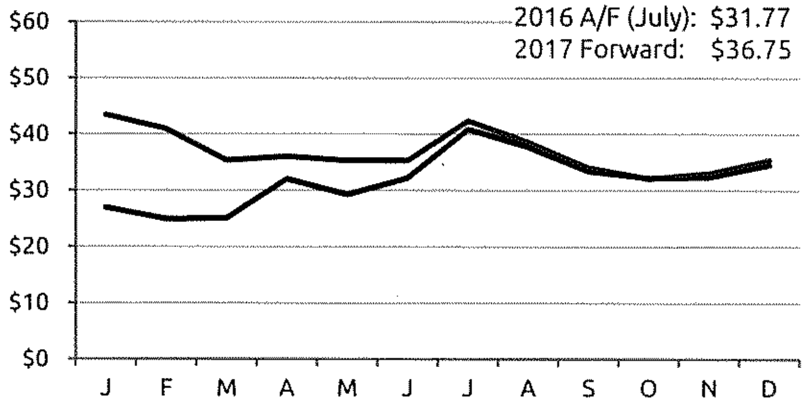
Gas Segment - Combined Cycle	2Q15	2Q16	YTD 2015	YTD 2016
Total Generation (MM MWh)				
California	0.8	0.7	1.2	1.4
NY/NE	3.8	3.5	5.8	6.7
PJM	7.9	7.2	10.5	16.6
In-Market-Availability				
California	90.4%	98.6%	94.4%	98.7%
NY/NE	89.9%	94.8%	96.9%	92.1%
PJM	99.0%	98.3%	98.8%	97.9%
Average Capacity Factor[1]				
California	34.0%	32.0%	26.7%	30.7%
NY/NE	51.6%	45.8%	53.8%	42.8%
PJM	72.4%	61.8%	73.4%	72.3%

[1] Average Capacity Factor is based on the NERC method of calculation, which uses a maximum capacity rating

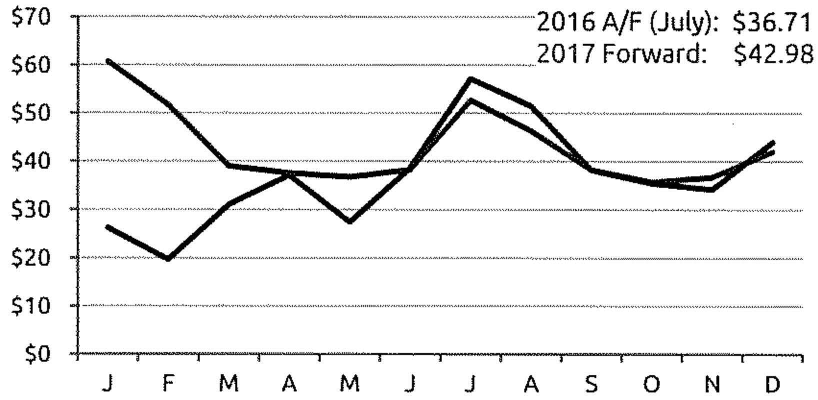
COMMODITY PRICING ON-PEAK POWER

2016 A/F (Jul)[1] — 2017 Forward

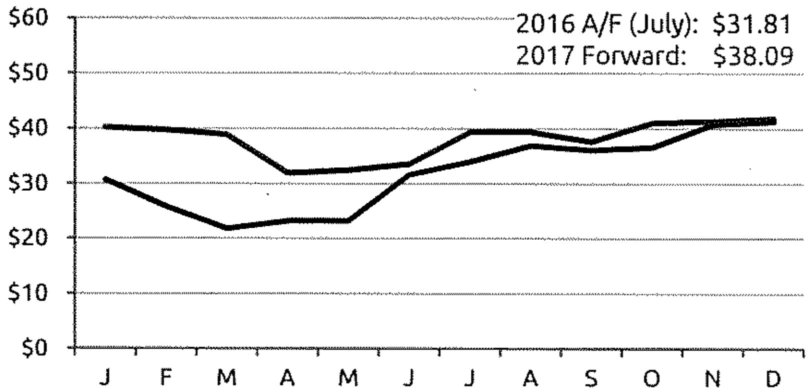
Indiana Hub ($/MWh)



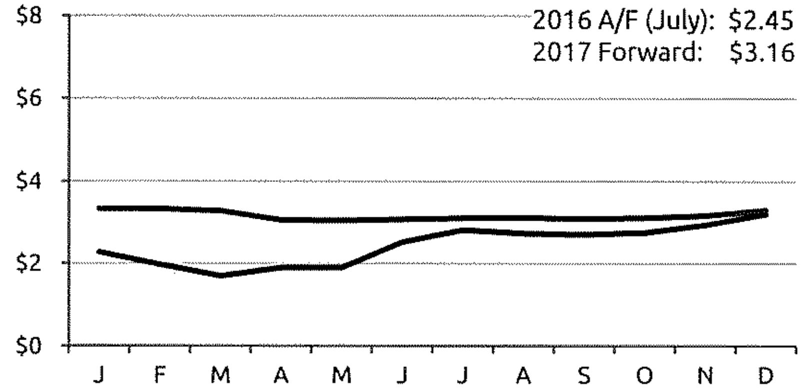
New York Zone A ($/MWh)



NP-15 ($/MWh)



Natural Gas ($/MMBtu)

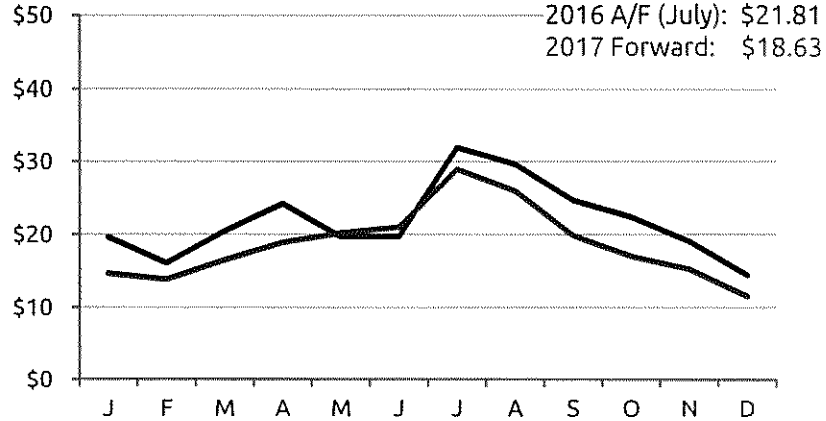


(1) Prices reflect actual day ahead on-peak settlement prices for 1/1/2016-7/13/2016 and quoted forward on-peak monthly prices for 7/14/2016-12/31/2016

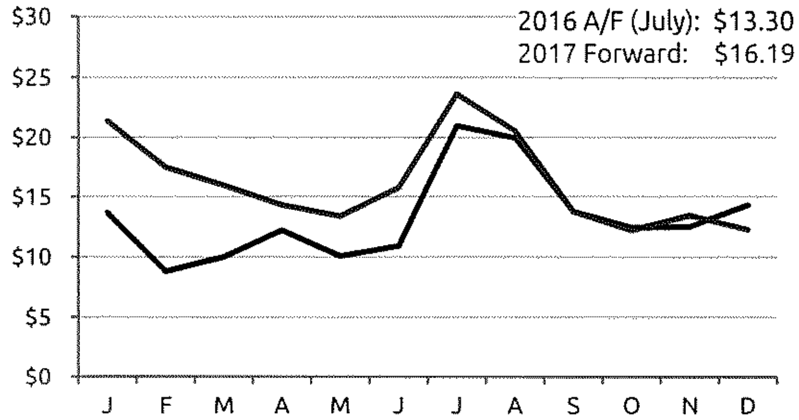
SPARK SPREADS ON-PEAK

2016 A/F (July)[1] 2017 Forward

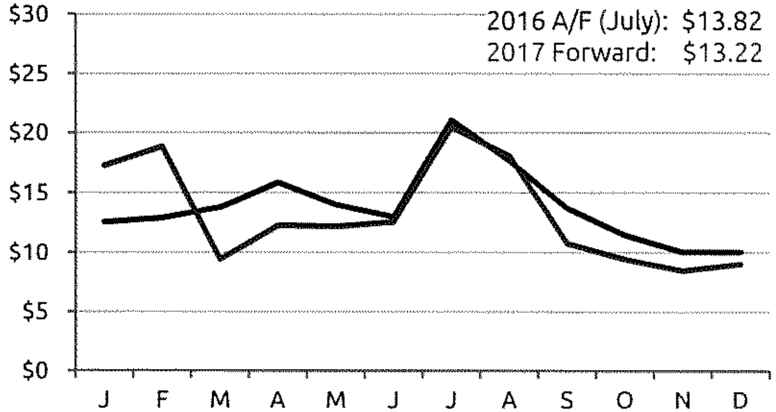
PJM West/TetM3 ($/MWh)



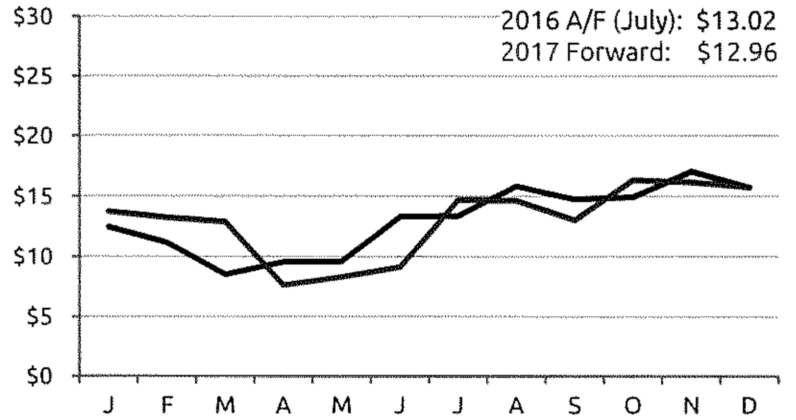
Mass Hub/Algonquin ($/MWh)



NI Hub/ChiCG ($/MWh)



NP-15/PGE ($/MWh)



(1) Prices reflect actual day ahead on-peak settlement prices for 1/1/2016-7/13/2016 and quoted forward on-peak monthly prices for 7/14/2016-12/31/2016

MARKET PRICING

Average Actual Power/Gas Prices ($/MWh)

	2Q15		2Q16		YTD 15		YTD 16	
	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Henry Hub ($/MMBtu)	$2.72		$2.11		$2.80		$2.04	
Indy Hub	$33.15	$23.89	$31.14	$22.37	$36.21	$26.43	$28.38	$21.27
Mass Hub	$29.16	$19.25	$28.17	$20.43	$62.67	$47.84	$31.01	$23.32
NP-15	$36.32	$29.12	$25.99	$19.93	$35.15	$28.84	$26.04	$20.67
NY - Zone A	$32.55	$16.75	$34.37	$17.18	$43.25	$28.11	$30.02	$15.54
PJM-W	$40.46	$26.74	$32.07	$22.29	$50.34	$35.20	$31.78	$23.94
AD Hub	$37.58	$25.92	$30.43	$21.71	$41.42	$29.09	$29.61	$22.32
NiHub	$31.47	$19.70	$28.87	$19.32	$36.15	$23.78	$28.11	$19.93

Average Trading Hub Spark Spreads ($/MWh)

	2Q15		2Q16		YTD 15		YTD 16	
	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
PJM West/TetM3	$29.38	$15.66	$21.15	$11.38	$23.46	$8.32	$19.94	$12.09
NiHub/ChiCG	$12.57	$0.80	$14.23	$4.68	$15.13	$2.75	$13.64	$5.47
NP-15/PGE	$14.99	$7.79	$10.76	$4.71	$13.82	$7.51	$10.74	$5.37
NY-Zone A/Dominion	$22.34	$6.54	$23.98	$6.79	$31.07	$15.93	$20.34	$5.86
Mass Hub/Algonquin	$13.48	$3.58	$11.02	$3.28	$14.21	($0.62)	$10.92	$3.23
AD Hub/Dominion	$24.19	$15.72	$27.53	$11.32	$40.02	$16.93	$29.68	$12.64

MISO CAPACITY POSITION (excludes PJM exports)

Price in $/kw-mo	Coal Segment	IPH	Total	EBITDA Contribution
PY 15/16				
MWs	516	2,576	3,092	
Average Price	$3.98	$2.03	$2.35	$88 MM
PY 16/17				
MWs	1,011	2,246	3,257	
Average Price	$2.75	$4.30	$3.81	$149 MM
PY 17/18				
MWs	579	1,862	2,441	
Average Price	$2.35	$4.65	$4.11	$120 MM
PY 18/19				
MWs	242	1,499	1,741	
Average Price	$2.68	$5.14	$4.80	$100 MM
PY 19/20				
MWs	185	570	755	
Average Price	$2.60	$5.20	$4.56	$41 MM
Total MWs	2,533	8,753	11,286	
Average Price	$2.89	$3.74	$3.68	$498 MM

Capacity Updates

- MISO planning year 2016/2017 cleared at $72/MW-day with Dynegy clearing no incremental MW beyond its Wholesale/Retail obligations
- Removal of Wood River from open position
- Addition of Joppa CTs to open position
- Removal of shutdowns from open position beginning planning year 2017/2018 (Newton Unit 2, Baldwin Unit 1 and Baldwin Unit 3)
- In July 2016, secured a conditional three-year 100 MW wholesale power purchase agreement to sell capacity and energy to Kentucky Municipal Energy Agency (KyMEA) beginning with Planning Year 2019/2020

Remaining Open Capacity Could Contribute to EBITDA Increase

- ~4.3 GW of MISO capacity remains available to sell for Planning Year 2017/2018 – 2019/2020[1]

[1] Load Serving Entities in MISO must have their capacity requirements met for Planning Year 2016/2017 by conclusion of the auction, so Planning Year 2017/2018 is the next period for which Load Serving Entities must procure capacity; [2] Assumes ~3,100 MW per planning year over PY 2017/2018 – PY 2019/2020

~47% of MISO capacity remains available for sale through PY 2019/2020[2]

PJM CAPACITY POSITION (includes MISO imports)

PJM Region	Planning Year	Average Price ($/MW-day)	MW Position	Average Price ($/MW-day)	MW Position
		Legacy/Base Product		Capacity Performance Product	
RTO	2015-2016	$131.91	5,109		
	2016-2017	$81.53	1,214	$134.00	3,992
	2017-2018	$120.28	2,484	$151.50	3,207
	2018-2019	$149.98	1,734	$164.77	3,905
	2019-2020	$80.00	1,617	$100.00	3,452
ComEd	2015-2016	$136.04	3,088		
	2016-2017	$66.98	708	$134.00	2,447
	2017-2018	$120.63	1,248	$151.50	2,261
	2018-2019	$200.21	0	$215.21	3,112
	2019-2020	$182.77	0	$202.77	3,461
MAAC	2015-2016	$167.61	507		
	2016-2017	$119.13	453	$134.00	50
	2017-2018	$120.00	0	$151.50	508
	2018-2019	$149.98	0	$166.82	508
	2019-2020	$80.00	0	$127.21	515
EMAAC	2015-2016	$167.43	535		
	2016-2017	$119.53	485	$134.00	52
	2017-2018	$120.00	8	$151.50	533
	2018-2019	$210.63	0	$225.42	532
	2019-2020	$99.77	0	$119.77	534
ATSI	2015-2016	$427.98	296		
	2016-2017	$115.75	361	$134.00	0
	2017-2018	$121.65	374	$151.50	0
	2018-2019	$149.98	0	$164.77	195
	2019-2020	$80.00	0	$100.00	224

Note: PJM capacity position represent volumes cleared and purchased in primary annual auctions, incremental auctions, and transitional auctions. Also includes bilateral transactions

ISO-NE / CAISO CAPACITY POSITIONS

Capacity / Resource Adequacy

ISO/Region	Contract Type	Average Price	Size (MWs)	Tenor
ISO-NE[1]	ISO-NE Capacity Auction	\$3.31/kw-Mo	3,738	June 2015 to May 2016
		\$3.25/kw-Mo	3,663	June 2016 to May 2017
		\$6.99/kw-Mo	2,181	June 2017 to May 2018
		\$9.64/kw-Mo	2,195	June 2018 to May 2019
		\$7.03/kw-Mo	2,240	June 2019 to May 2020
NYISO[2][3]	ICAP	\$2.19/kw-Mo	1,124	Winter 2015/2016
		\$3.36/kw-Mo	915	Summer 2016
		\$2.64/kw-Mo	766	Winter 2016/2017
		\$3.44/kw-Mo	868	Summer 2017
		\$3.14/kw-Mo	545	Winter 2017/18
		\$3.69/kw-Mo	515	Summer 2018
		\$3.30/kw-Mo	293	Winter 2018/2019
		\$3.38/kw-Mo	225	Summer 2019
CAISO[4]	RA Capacity		91	Avg Bilateral Sold Q2 2016
			801	Avg Bilateral Sold Q3 2016
			230	Avg Bilateral Sold Q4 2016
			725	Avg Bilateral Sold Cal 2017
			400	Avg Bilateral Sold Cal 2018
			850	Avg Bilateral Sold Cal 2019

[1] ISO-NE represents capacity auctions results, supplemental auctions and bilateral capacity sales; [2] NYISO represents capacity auction results and bilateral capacity sales; [3] Winter period covers November through April and the Summer period covers May through October; [4] Dynegy is prohibited from disclosing RA capacity sales through 2016 at Moss Landing 6&7

APPENDIX

REG G RECONCILIATIONS

DYNEGY

REG G RECONCILIATION – 2ND QUARTER 2015 ADJUSTED EBITDA

DYNEGY INC.
REPORTED SEGMENTED RESULTS OF OPERATIONS
THREE MONTHS ENDED JUNE 30, 2015
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the three months ended June 30, 2015:

	Three Months Ended June 30, 2015				
	Coal	IPH	Gas	Other	Total
Net income attributable to Dynegy Inc.					$ 388
Plus / (Less):					
Loss attributable to noncontrolling interest					(2)
Income tax benefit					(501)
Interest expense					132
Depreciation and amortization expense					174
EBITDA (1)	$ 33	$ (3)	$ 213	$ (52)	$ 191
Plus / (Less):					
Adjustments to reflect Adjusted EBITDA from unconsolidated investments and exclude noncontrolling interest	—	2	—	—	2
Acquisition and integration costs	—	—	—	23	23
Mark-to-market adjustments, including warrants	(14)	6	(10)	(3)	(21)
Other	—	—	(1)	(1)	(2)
Adjusted EBITDA (1)(2)	$ 19	$ 5	$ 202	$ (33)	$ 193

(1) EBITDA and Adjusted EBITDA are non-GAAP financial measures. Please refer to Item 2.02 of our Form 8-K filed on August 3, 2016, for definitions, utility and uses of such non-GAAP financial measures. A reconciliation of EBITDA to Operating income (loss) is presented below. Management does not allocate interest expense and income taxes on a segment level and therefore uses Operating income (loss) as the most directly comparable GAAP measure.

(2) Not adjusted for these items which are excluded in 2016: (i) non-cash compensation expense of $8 million, and (ii) Wood River's energy margin and O&M costs of $9 million.

	Three Months Ended June 30, 2015				
	Coal	IPH	Gas	Other	Total
Operating income (loss)	$ (5)	$ (14)	$ 86	$ (57)	$ 10
Depreciation and amortization expense	38	11	124	1	174
Earnings from unconsolidated investments	—	—	3	—	3
Other income and expense, net	—	—	—	4	4
EBITDA	$ 33	$ (3)	$ 213	$ (52)	$ 191

REG G RECONCILIATION – 2ND QUARTER 2016 ADJUSTED EBITDA

DYNEGY INC.
REPORTED SEGMENTED RESULTS OF OPERATIONS
THREE MONTHS ENDED JUNE 30, 2016
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the three months ended June 30, 2016:

	Three Months Ended June 30, 2016				
	Coal	IPH	Gas	Other	Total
Net loss attributable to Dynegy Inc.					$ (801)
Plus / (Less):					
Loss attributable to noncontrolling interest					(2)
Income tax benefit					(9)
Interest expense					141
Depreciation and amortization expense					164
EBITDA (1)	$ (716)	$ 20	$ 235	$ (46)	$ (507)
Adjustments to reflect Adjusted EBITDA from unconsolidated investments and exclude noncontrolling interest	—	2	1	—	3
Acquisition and integration costs	—	(8)	—	5	(3)
Mark-to-market adjustments, including warrants	83	(2)	(52)	—	29
Impairments	645	—	—	—	645
Wood River energy margin and O&M	15	—	—	—	15
Non-cash compensation expense	—	—	—	5	5
Other	(1)	(1)	—	2	—
Adjusted EBITDA (1)	$ 26	$ 11	$ 184	$ (34)	$ 187

(1) EBITDA and Adjusted EBITDA are non-GAAP financial measures. Please refer to Item 2.02 of our Form 8-K filed on August 3, 2016, for definitions, utility and uses of such non-GAAP financial measures. A reconciliation of EBITDA to Operating income (loss) is presented below. Management does not allocate interest expense and income taxes on a segment level and therefore uses Operating income (loss) as the most directly comparable GAAP measure.

	Three Months Ended June 30, 2016				
	Coal	IPH	Gas	Other	Total
Operating income (loss)	$ (749)	$ 3	$ 90	$ (46)	$ (702)
Depreciation and amortization expense	27	3	132	2	164
Earnings from unconsolidated investments	—	—	1	—	1
Other income and expense, net	6	14	12	(2)	30
EBITDA	$ (716)	$ 20	$ 235	$ (46)	$ (507)

REG G RECONCILIATION – PRIOR YEAR-TO-DATE ADJUSTED EBITDA

DYNEGY INC.
REPORTED SEGMENTED RESULTS OF OPERATIONS
SIX MONTHS ENDED JUNE 30, 2015
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the six months ended June 30, 2015:

	Six Months Ended June 30, 2015				
	Coal	**IPH**	**Gas**	**Other**	**Total**
Net income attributable to Dynegy Inc.					$ 208
Plus / (Less):					
Loss attributable to noncontrolling interest					(3)
Income tax benefit					(501)
Interest expense					268
Depreciation and amortization expense					238
EBITDA (1)	$ 50	$ 29	$ 308	$ (177)	$ 210
Plus / (Less):					
Adjustments to reflect Adjusted EBITDA from unconsolidated investments and exclude noncontrolling interest	—	3	—	—	3
Acquisition and integration costs	—	—	—	113	113
Mark-to-market adjustments, including warrants	(21)	(5)	(23)	2	(47)
Other	—	—	(1)	—	(1)
Adjusted EBITDA (1)(2)	$ 29	$ 27	$ 284	$ (62)	$ 278

(1) EBITDA and Adjusted EBITDA are non-GAAP financial measures. Please refer to Item 2.02 of our Form 8-K filed on August 3, 2016, for definitions, utility and uses of such non-GAAP financial measures. A reconciliation of EBITDA to Operating income (loss) is presented below. Management does not allocate interest expense and income taxes on a segment level and therefore uses Operating income (loss) as the most directly comparable GAAP measure.

(2) Not adjusted for these items which are excluded in 2016: (i) non-cash compensation expense of $14 million, and (ii) Wood River's energy margin and O&M costs of $8 million.

	Six Months Ended June 30, 2015				
	Coal	**IPH**	**Gas**	**Other**	**Total**
Operating income (loss)	$ 2	$ 8	$ 138	$ (178)	$ (30)
Depreciation and amortization expense	48	21	167	2	238
Earnings from unconsolidated investments	—	—	3	—	3
Other income and expense, net	—	—	—	(1)	(1)
EBITDA	$ 50	$ 29	$ 308	$ (177)	$ 210

REG G RECONCILIATION – CURRENT YEAR-TO-DATE ADJUSTED EBITDA

DYNEGY INC.
REPORTED SEGMENTED RESULTS OF OPERATIONS
SIX MONTHS ENDED JUNE 30, 2016
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the six months ended June 30, 2016:

	Six Months Ended June 30, 2016				
	Coal	IPH	Gas	Other	Total
Net loss attributable to Dynegy Inc.					$ (811)
Plus / (Less):					
Loss attributable to noncontrolling interest					(2)
Income tax expense					7
Interest expense					283
Depreciation and amortization expense					354
EBITDA (1)	$ (632)	$ 44	$ 506	$ (87)	$ (169)
Plus / (Less):					
Adjustments to reflect Adjusted EBITDA from unconsolidated investments and exclude noncontrolling interest	—	2	4	—	6
Acquisition and integration costs	—	(8)	—	9	1
Mark-to-market adjustments, including warrants	43	(5)	(114)	(1)	(77)
Impairments	645	—	—	—	645
Wood River energy margin and O&M	20	—	—	—	20
Non-cash compensation expense	—	—	1	11	12
Other	—	(1)	(1)	2	—
Adjusted EBITDA (1)	$ 76	$ 32	$ 396	$ (66)	$ 438

(1) EBITDA and Adjusted EBITDA are non-GAAP financial measures. Please refer to Item 2.02 of our Form 8-K filed on August 3, 2016, for definitions, utility and uses of such non-GAAP financial measures. A reconciliation of EBITDA to Operating income (loss) is presented below. Management does not allocate interest expense and income taxes on a segment level and therefore uses Operating income (loss) as the most directly comparable GAAP measure.

	Six Months Ended June 30, 2016				
	Coal	IPH	Gas	Other	Total
Operating income (loss)	$ (695)	$ 17	$ 210	$ (89)	$ (557)
Depreciation and amortization expense	57	13	281	3	354
Earnings from unconsolidated investments	—	—	3	—	3
Other income and expense, net	6	14	12	(1)	31
EBITDA	$ (632)	$ 44	$ 506	$ (87)	$ (169)

REG G RECONCILIATION – PRIOR DYNEGY 2016 ADJUSTED EBITDA AND FREE CASH FLOW GUIDANCE [(1)]

DYNEGY INC.
2016 ADJUSTED EBITDA AND FREE CASH FLOW GUIDANCE
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our 2016 Adjusted EBITDA guidance, updated based on April 19, 2016 forward curves, as presented on May 3, 2016:

	Dynegy Consolidated	
	Low	High
Net loss attributable to Dynegy Inc. (1)	$ (351)	$ (181)
Plus / (Less):		
Income tax expense (2)	16	16
Interest expense	540	545
Earnings from unconsolidated investments (2)	(2)	(2)
Operating Income	203	378
Depreciation expense	710	730
Amortization expense	30	30
Earnings from unconsolidated investments (2)	2	2
EBITDA (3)	945	1,140
Plus / (Less):		
Earnings from unconsolidated investments (2)	(2)	(2)
Acquisition and integration costs	35	40
Other (4)	22	22
Adjusted EBITDA (3)	$ 1,000	$ 1,200

(1) For purposes of Net loss attributable to Dynegy Inc. guidance reconciliation, mark-to-market adjustments and changes in the fair value of common stock warrants are assumed to be zero.

(2) Represents actual amounts for the three months ended March 31, 2016.

(3) EBITDA and Adjusted EBITDA are non-GAAP measures.

(4) Represents actual amounts for three months ended March 31, 2016. Other consists primarily of cash distributions from unconsolidated investments, asset retirement obligation accretion, non-cash compensation expense, and energy margin and operating and maintenance costs associated with our Wood River facility.

The following table provides summary financial data regarding our 2016 Free Cash Flow guidance:

	Dynegy Consolidated	
	Low	High
Adjusted EBITDA (1)	$ 1,000	$ 1,200
Cash interest payments	(515)	(515)
Acquisition and integration costs	(35)	(40)
Other cash items	10	10
Cash Flow from Operations	460	655
Maintenance capital expenditures	(275)	(275)
Environmental capital expenditures	(20)	(20)
Acquisition and integration costs	35	40
Free Cash Flow (1)	$ 200	$ 400

(1) Adjusted EBITDA and Free Cash Flow are non-GAAP measures.

[(1)] As presented on May 4, 2016

REG G RECONCILIATION – REVISED DYNEGY 2016 ADJUSTED EBITDA AND FREE CASH FLOW GUIDANCE

Ex. TC-4

DYNEGY INC.
2016 ADJUSTED EBITDA AND FREE CASH FLOW GUIDANCE
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our 2016 Adjusted EBITDA guidance, updated based on July 14, 2016 forward curves, as presented on August 3, 2016:

	Dynegy Consolidated	
	Low	High
Net loss attributable to Dynegy Inc. (1)	$ (1,038)	$ (968)
Plus / (Less):		
Loss attributable to noncontrolling interest (2)	(2)	(2)
Income tax expense (2)	7	7
Other income and expense, net (2)	(31)	(31)
Interest expense	605	610
Earnings from unconsolidated investments (2)	(3)	(3)
Operating loss	(462)	(387)
Depreciation and amortization expense	700	720
Earnings from unconsolidated investments (2)	3	3
Other income and expense, net (2)	31	31
EBITDA (3)	272	367
Plus / (Less):		
Acquisition and integration costs	45	50
Impairments (2)	645	645
Other (4)	38	38
Adjusted EBITDA (3)	$ 1,000	$ 1,100

(1) For purposes of Net loss attributable to Dynegy Inc. guidance reconciliation, mark-to-market adjustments and changes in the fair value of common stock warrants are assumed to be zero.

(2) Represents actual amounts for the six months ended June 30, 2016.

(3) EBITDA and Adjusted EBITDA are non-GAAP measures.

(4) Represents actual amounts for six months ended June 30, 2016. Other consists primarily of adjustments to reflect Adjusted EBITDA from unconsolidated investment and exclude noncontrolling interest, non-cash compensation expense, and Wood River's energy margin and operating and maintenance costs.

The following table provides summary financial data regarding our 2016 Free Cash Flow guidance:

	Dynegy Consolidated	
	Low	High
Adjusted EBITDA (1)	$ 1,000	$ 1,100
Cash interest payments (2)	(515)	(515)
Acquisition and integration costs	(45)	(50)
Other cash items	10	10
Cash Flow from Operations	450	545
Maintenance capital expenditures	(275)	(275)
Environmental capital expenditures	(20)	(20)
Acquisition and integration costs	45	50
Free Cash Flow (1)	$ 200	$ 300

(1) Adjusted EBITDA and Free Cash Flow are non-GAAP measures.

(2) Excludes payments to an escrow account of (i) $50 million of pre-funded interest and (ii) $20 million of pre-funded original issue discount which are contingent upon the closing of the Delta Transaction.

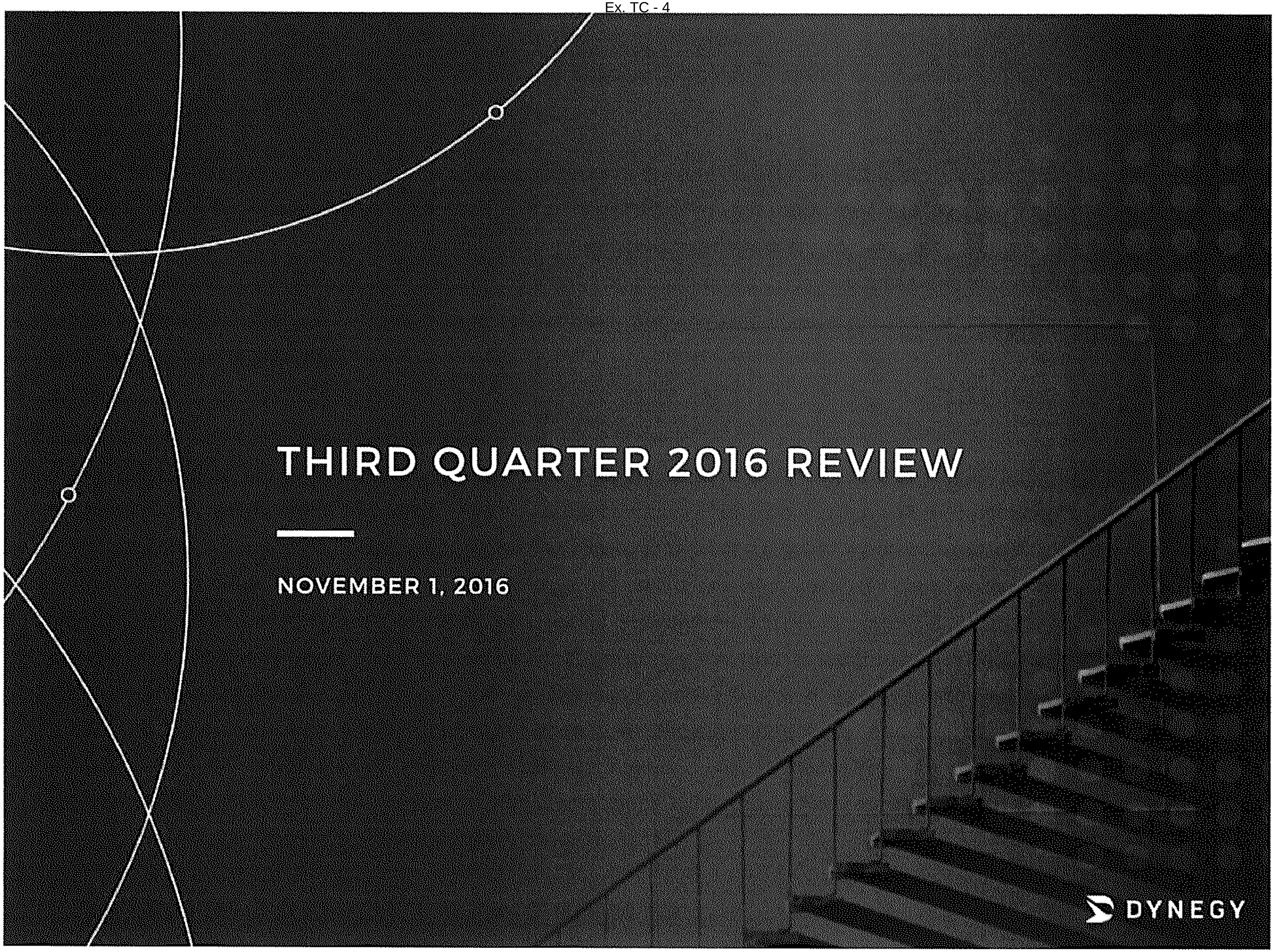
REG G RECONCILIATION – IPH 2016 ADJUSTED EBITDA GUIDANCE

ILLINOIS POWER HOLDINGS (IPH)
2016 ADJUSTED EBITDA GUIDANCE
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our IPH 2016 Adjusted EBITDA guidance, based on July 14, 2016 forward curves, as presented on August 3, 2016:

Operating income	$	78
Depreciation and amortization expense		30
EBITDA (1)		108
Plus / (Less):		
Acquisition and integration costs		(8)
Adjusted EBITDA (1)	$	100

(1) Adjusted EBITDA is a non-GAAP measure. Management does not allocate interest expense and income taxes on a segment level and therefore uses Operating Income (Loss) as the most directly comparable GAAP measure.


THIRD QUARTER 2016 REVIEW
NOVEMBER 1, 2016
DYNEGY

FORWARD-LOOKING STATEMENTS

Cautionary Statement Regarding Forward-Looking Statements

This presentation contains statements reflecting assumptions, expectations, projections, intentions or beliefs about future events that are intended as "forward looking statements." You can identify these statements by the fact that they do not relate strictly to historical or current facts. Management cautions that any or all of Dynegy's forward-looking statements may turn out to be wrong. Please read Dynegy's annual, quarterly and current reports filed under the Securities Exchange Act of 1934, including its 2015 Form 10-K and first, second, and third quarter 2016 Forms 10-Q, when filed, for additional information about the risks, uncertainties and other factors affecting these forward-looking statements and Dynegy generally. Dynegy's actual future results may vary materially from those expressed or implied in any forward-looking statements. All of Dynegy's forward-looking statements, whether written or oral, are expressly qualified by these cautionary statements and any other cautionary statements that may accompany such forward-looking statements. In addition, Dynegy disclaims any obligation to update any forward-looking statements to reflect events or circumstances after the date hereof.

Non-GAAP Financial Measures

This presentation contains non-GAAP financial measures including EBITDA, Adjusted EBITDA and Free Cash Flow. Reconciliations of these measures to the most directly comparable GAAP financial measures to the extent available without unreasonable effort are contained herein. To the extent required, statements disclosing the definitions, utility and purposes of these measures are set forth in Item 2.02 to our current report on Form 8-K filed with the SEC on November 1, 2016, which is available on our website free of charge, www.dynegy.com.

TABLE OF CONTENTS: THIRD QUARTER 2016 REVIEW

OVERVIEW AND OUTLOOK

2016 FINANCIAL UPDATE

- 3Q16 Net Loss of $249 MM versus Net Loss of $24 MM in 3Q15
- 3Q16 Adjusted EBITDA of $350 MM versus $350 MM in 3Q15
- Affirming 2016 Adjusted EBITDA and Free Cash Flow guidance
- $750 MM senior notes offering in October 2016

PORTFOLIO REALIGNMENT (ADDITIONS)

- Awaiting FERC approval for ENGIE closing
- Restructuring Support Agreement reached with ~70% of Genco bondholders
- 632 MW of low-cost uprates and unit refurbishments to be installed by 2016
- Baldwin unit 1 to remain online through Planning Year 2017/2018 to support incremental bilateral capacity sales

PORTFOLIO REALIGNMENT (SUBTRACTIONS)

- Newton unit 2 retired in September 2016
- Baldwin unit 3 mothballed in October 2016
- Filed notice with the CAISO to retire Moss Landing units 6 & 7
- Awaiting FERC approval for Elwood sale

2017 OUTLOOK (ASSUMES ENGIE & ELWOOD CLOSINGS IN 2016)

- 2017 Adjusted EBITDA guidance initiated at $1,200 - 1,400 MM
- 2017 Free Cash Flow guidance initiated at $150 - 350 MM
- Approximately 70% of Dynegy's 2017 gross margin secured through capacity sales and hedged energy margin
- ENGIE portfolio will add ~35 MM MWhrs of unhedged generation at closing

GENCO RESTRUCTURING: STATUS UPDATE & NEXT STEPS

Current Status

- Entered restructuring support agreement (RSA) with Genco and ad hoc group of Genco bondholders (Ad Hoc Group) to restructure $825 million in unsecured notes at Genco
- Participating Genco bondholders at ~70%[1], above the 66.7% threshold

Next Steps

- November 2016: Launch exchange offer and prepack solicitation
- December 2016: If 97% (or greater) of Genco notes are tendered, then exchange offer effectuated out of court. If less than 97% of Genco notes are tendered, Genco will commence a prepackaged Chapter 11 process.
  - If restructuring effectuated through a prepackaged Chapter 11 process, participating non-accredited investors will receive cash in lieu of unsecured notes and warrants; the amount of notes and warrants issued by Dynegy at that time will be reduced by a like amount
  - Non-accredited investors believed to own less than 20% of the outstanding Genco bonds
- First Quarter 2017: Anticipated completion of the Genco restructuring

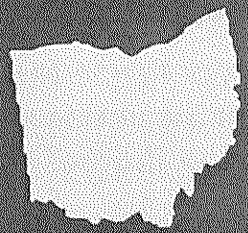
Genco restructuring results in significant reduction in debt and interest expense, and simplifies Dynegy's capital and organizational structures

(1) Percentage based on principal held

REGULATORY LANDSCAPE

New York

- NY ZEC Program interferes with wholesale markets
- Lawsuit filed in U.S. District Court on October 19, 2016
- Initial pretrial conference set for early December 2016; expect decision mid-2017



Ohio

- FirstEnergy Distribution Modernization Rider will go to rehearing; expect various groups to file lawsuits with Ohio Supreme Court
- DP&L case schedule has been set; expect settlement talks to occur prior to hearing
- AEP re-regulation proposals could potentially occur as soon as spring 2017

Illinois

- MISO expects to file its Forward Resource Auction (FRA) design in November 2016
- Legislative push for a comprehensive energy package expected during fall veto session in November 2016

Dynegy continues to defend the competitive model by challenging out-of-market subsidies

Ex. TC - 4

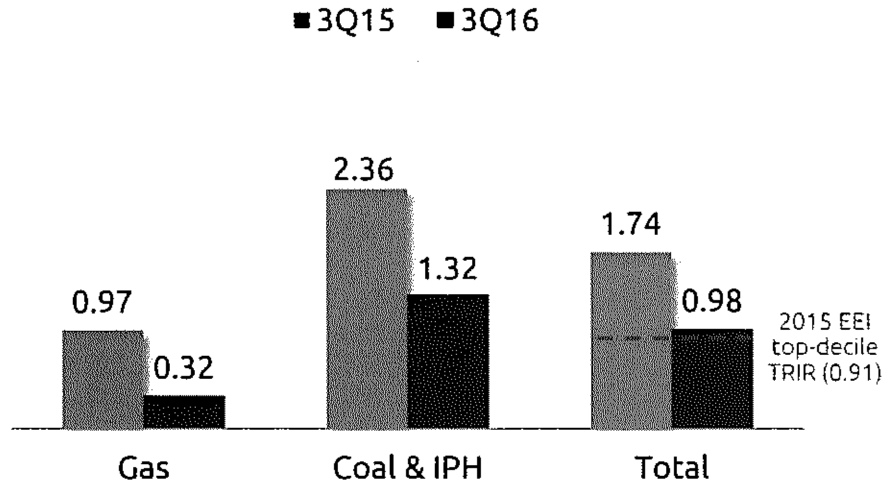
OPERATIONS OVERVIEW

MARTY DALEY, CHIEF OPERATING OFFICER

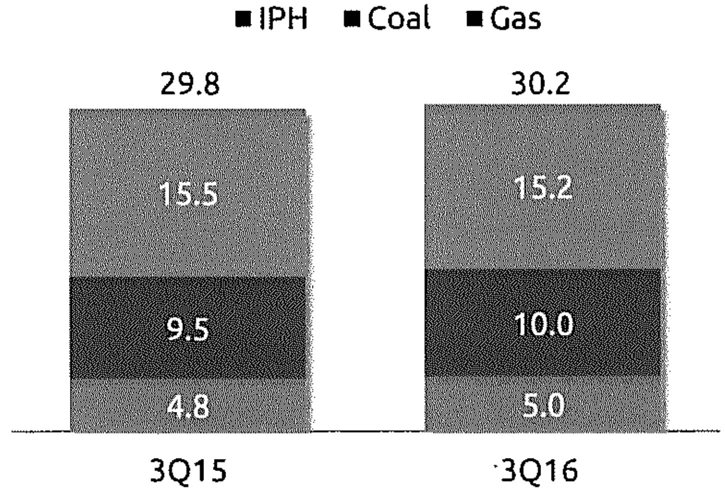
DYNEGY

OPERATIONS SUMMARY

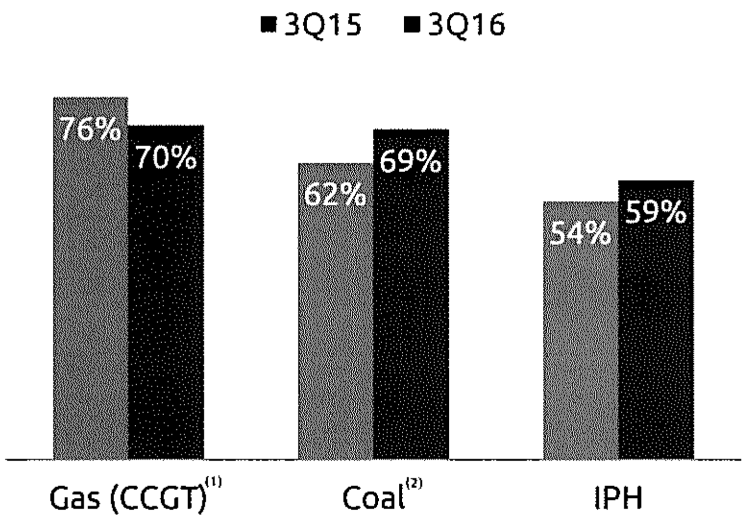
Safety Performance - Total Recordable Incident Rate (TRIR)



Generation Volumes (MM MWh)



Net Capacity Factors



Operations Update

Safety Performance

- Gas fleet continues to perform in the top decile
- Coal fleet improvements due to focused safety initiatives
- Implementation of Voluntary Protection Program (VPP) across the fleet

Generation Volumes

- Coal segment volumes increased primarily due to improved reliability in PJM coal units and stronger pricing in MISO, offset by Wood River retirement

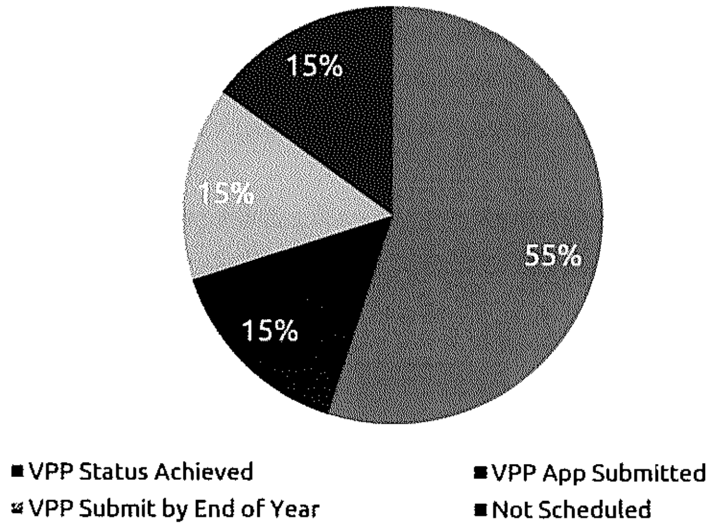
Net Capacity Factors

- Gas segment capacity factors declined primarily due to lower volumes at Moss Landing driven by a significant increase in its gas transportation costs
- Coal segment and IPH capacity factors improved primarily due to higher pricing in MISO and improved reliability

(1) Excludes Casco Bay (Facility under a tolling arrangement); (2) Excludes Brayton Point

OSHA VOLUNTARY PROTECTION PROGRAM (VPP)

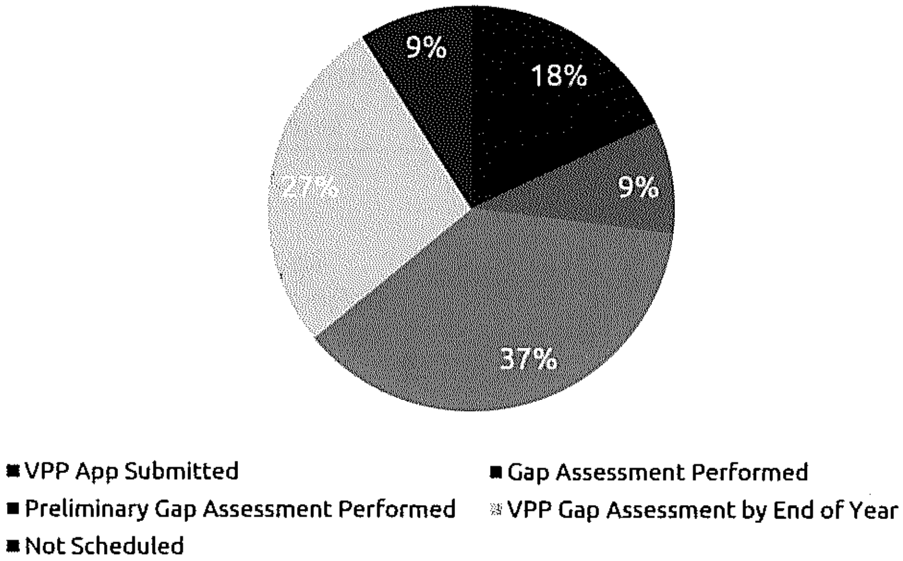
Combined Cycle Gas-Fueled Facilities



VPP Status

Not Scheduled	VPP Submit by End of Year	VPP App Submitted	VPP Status Achieved
2	2	2	7

Coal-Fueled Facilities



VPP Status[1]

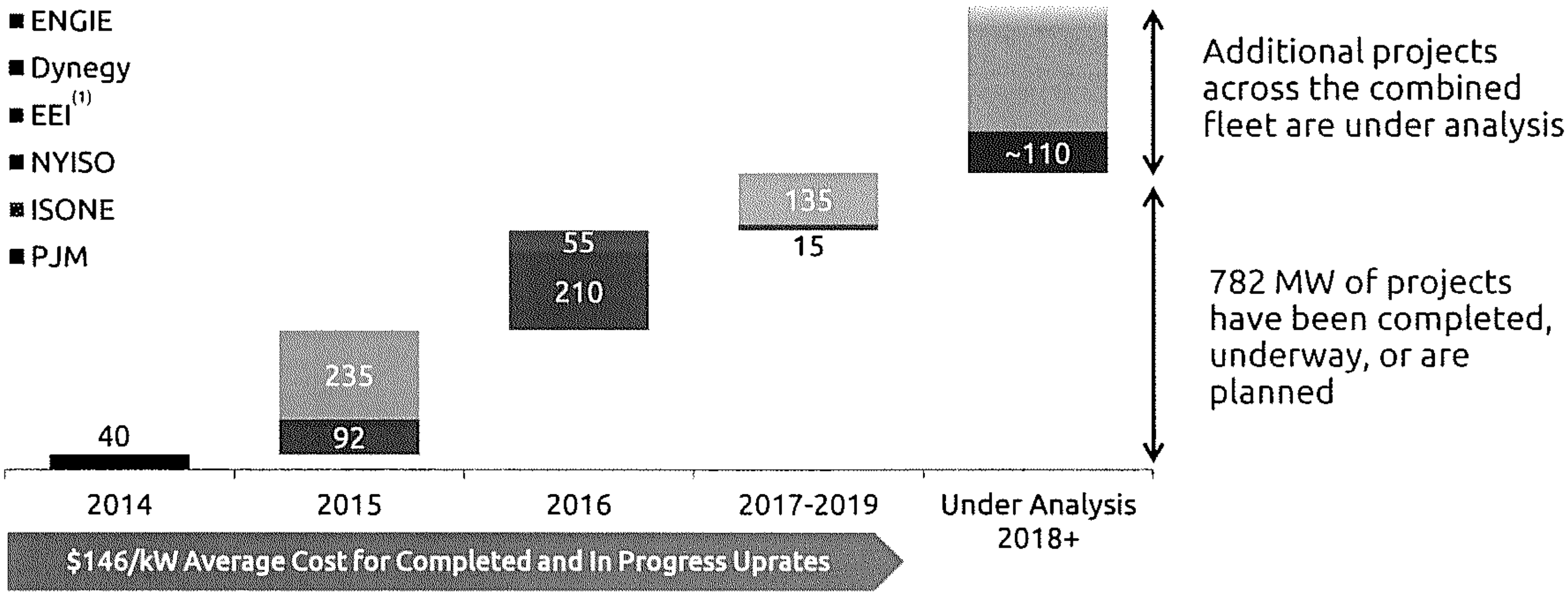
Not Scheduled	VPP Gap Assessment by End of Year	Preliminary Gap Assessment Performed	Gap Assessment Performed	VPP App Submitted
1	3	4	1	2

70% of Dynegy-operated facilities have achieved, or are pursuing, OSHA VPP status

(1) Excludes Brayton Point

FLEETWIDE EXPANSION THROUGH LOW-COST UPRATES

Capacity Uprates (MW of Additional Capacity by Market)



- Lower LTSA costs and increased scale has created opportunities for low-cost uprates
- 632 MW of low-cost uprates and unit refurbishments to be installed by December 2016 at an average cost of $135/kW
- 150 MW of additional capacity scheduled to be installed by 2019 at an average cost of $194/kW
- Further uprate projects are under analysis including uprates to the ENGIE fleet[2]

Fleet expansions at a fraction of new build cost

[1] 235 MW at EEI associated with the refurbishment of mothballed Joppa CTs; EEI can sell into TVA, KU, and MISO; [2] ENGIE transaction expected to close in 4Q16

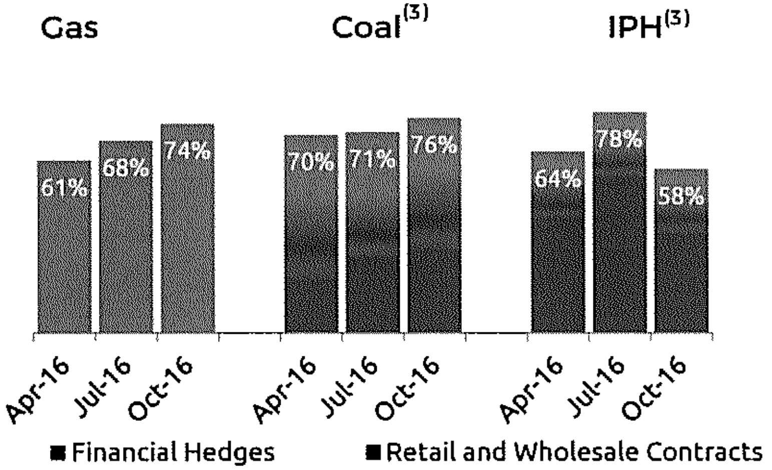
COMMERCIAL OVERVIEW

HANK JONES, CHIEF COMMERCIAL OFFICER

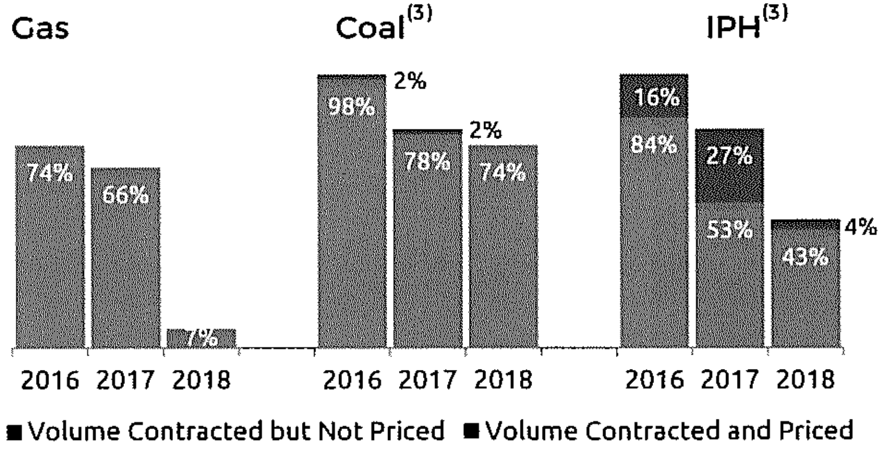
DYNEGY

COMMERCIAL SUMMARY

2016 Generation Volumes Hedged by Segment(1)

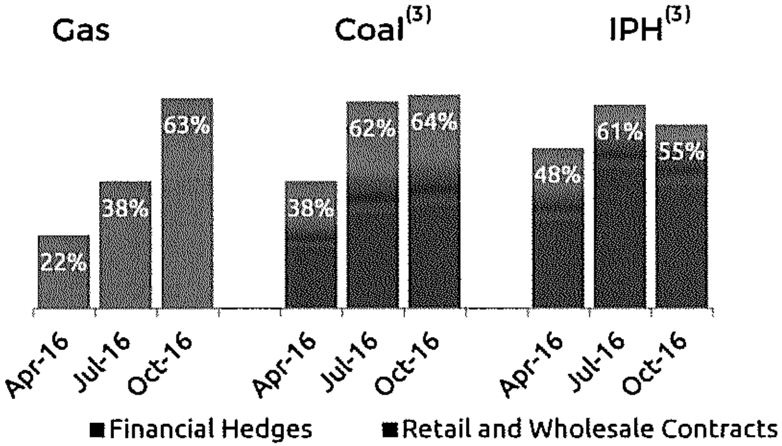


Fuel Supply Hedged by Segment(2)



Contracted Rail and Barge Transportation	2016	2017	2018-2020
Coal segment	100%	99%	69%
IPH	100%	100%	67%

2017 Generation Volumes Hedged by Segment(2)

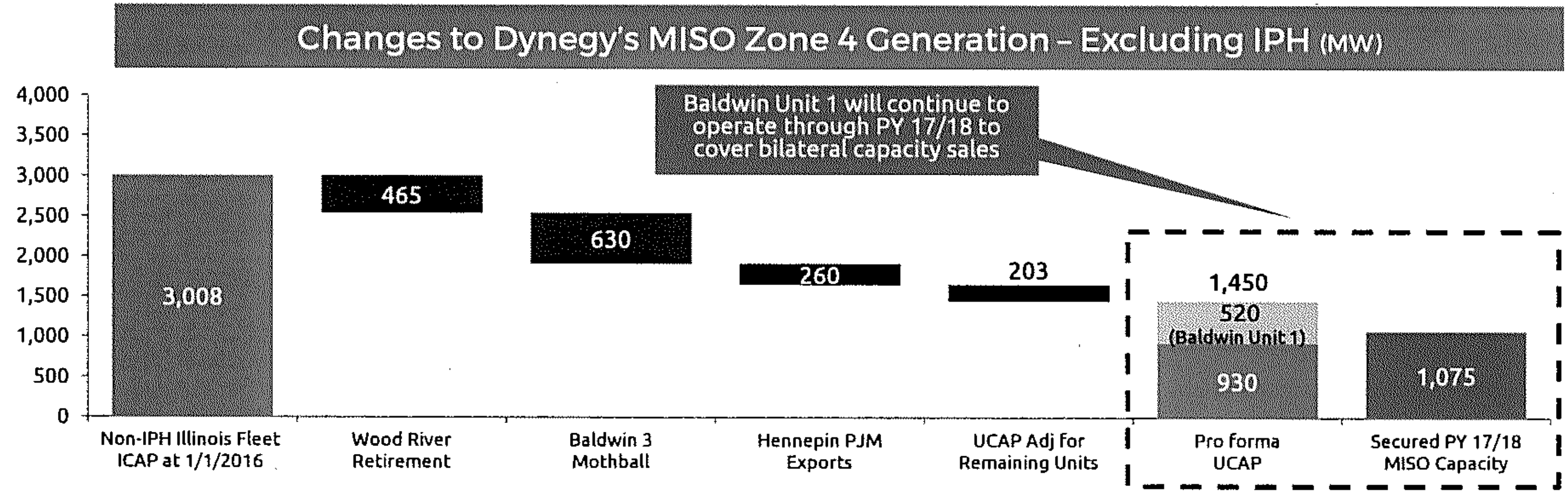


- Gas segment hedges lock in attractive spark spreads whereas the open position in PJM provides protection against declining gas prices
- Decline in IPH hedge percentages due to expected uplift in run times through additional emission control investments
- IPH currently hedged by retail sales
- 2016 on-peak Coal segment ~82% hedged for balance of year

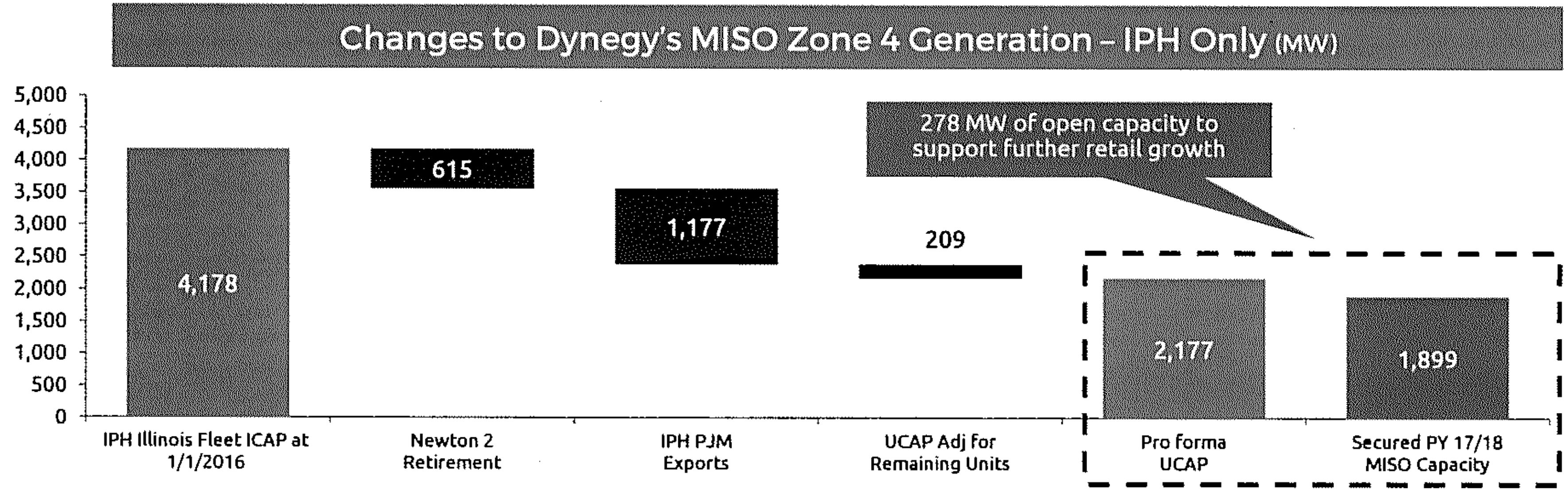
(1) Balance of the year as of 4/19/2016, 7/14/2016 and 10/12/2016; (2) As of 10/12/2016; excludes ENGIE generation volumes; (3) 2016 - 2018 excludes Brayton Point; Newton unit 2, and Baldwin unit 3 excluded as of Oct 2016

RIGHTSIZING OUR MISO PORTFOLIO

COAL SEGMENT



IPH



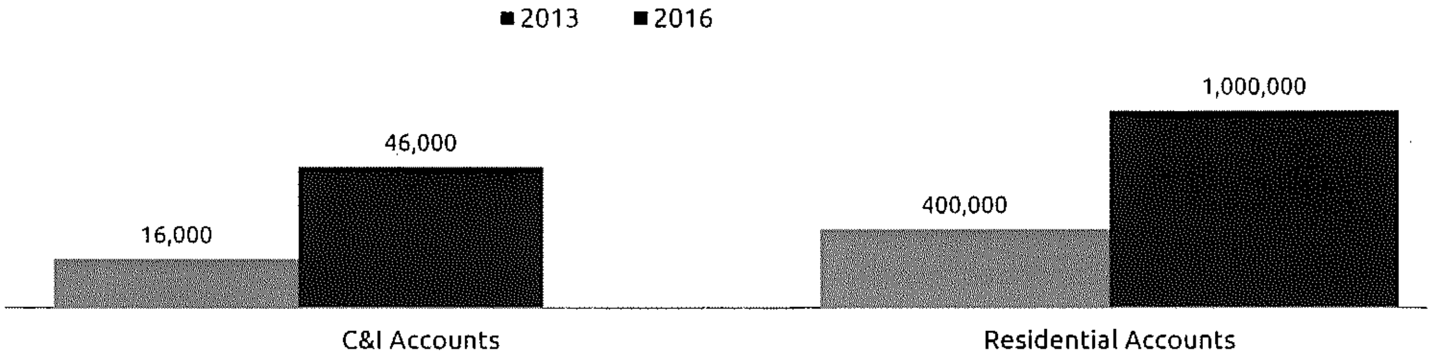
MISO portfolio designed to match generation supply with retail and wholesale load obligations

Note: Unit capabilities are based on winter capacity ratings

GROWING RETAIL BUSINESS

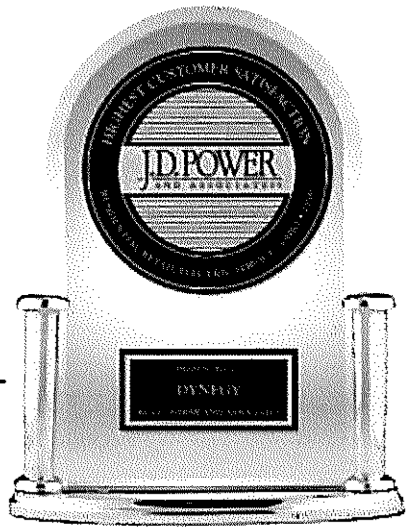
Dynegy will continue to expand its retail business through acquisitions and organic growth

Recent Growth (IL & OH)



Superior Service

- Dynegy was named by J.D. Power the "Highest in Residential Customer Satisfaction with Retail Electric Service in Ohio" for 2016
- Dynegy scored #1 in Retailer Overall Satisfaction Scores, according to DNV GL Channel Partner Survey[1]



Future Growth

- Retail licensing expansion underway in 7 utility territories across Pennsylvania (5) and Massachusetts (2)

Focusing on future growth that is backed by Dynegy's generating assets

[1] DNV GL is a global testing and advisory service provider to the energy value chain. Its Channel Partner Market Survey is a national assessment of agencies, aggregators, brokers and consultants in the retail energy markets

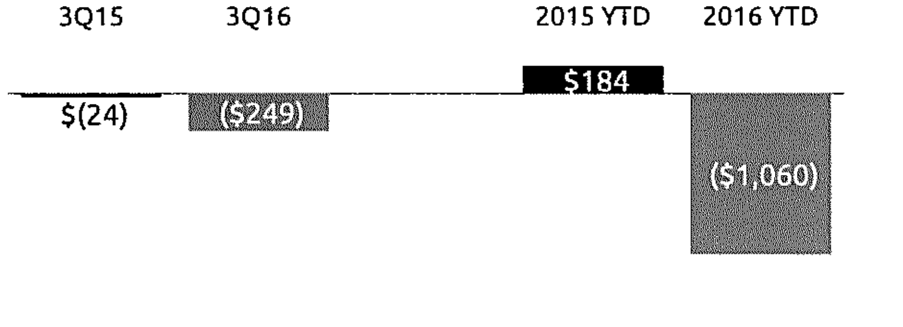
THIRD QUARTER 2016 FINANCIAL RESULTS & 2017 GUIDANCE

CLINT FREELAND, CHIEF FINANCIAL OFFICER

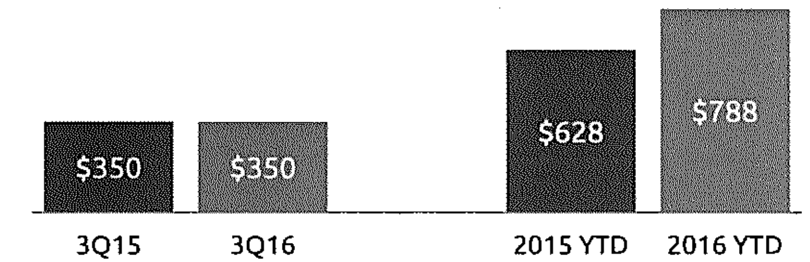
DYNEGY

FINANCIAL SUMMARY

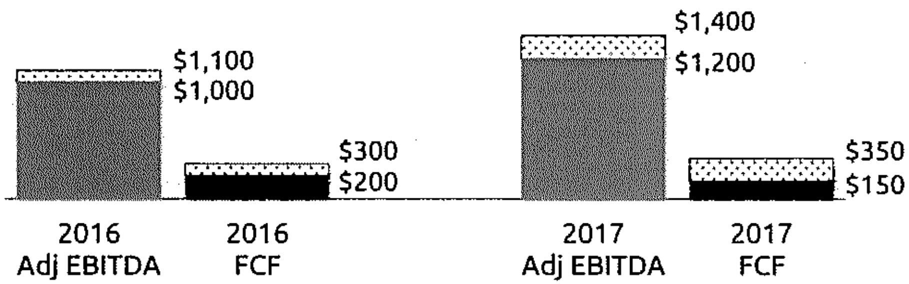
Net Income/(Loss) ($ MM)



Adjusted EBITDA Results ($ MM)



Guidance ($ MM)



Liquidity as of 9/30/2016 [1] ($ MM)

Unrestricted Cash at Dynegy Inc.	$1,351
Revolving Facilities & LC Availability at Dynegy Inc.	$1,098
Total Dynegy Inc. Liquidity (excluding IPH)	**$2,449**
Unrestricted Cash at IPH	$107
Revolver Facilities & LC Availability at IPH	$14
Total IPH Liquidity	**$121**

Financial Update

Adjusted EBITDA

- Flat quarter-over-quarter
- YTD 2016 increased as the addition of the Duke/ECP assets in 2Q15 more than offset lower realized energy margins and higher O&M from maintenance/uprate outages

Liquidity

- Dynegy Inc. liquidity includes:
  - Proceeds from TEU issuance in 2Q16
  - Proceeds from PJM capacity sale in 1Q16
- Dynegy Inc. liquidity excludes:
  - Proceeds from $2 billion term loan issuance in 2Q16
  - Proceeds from $750 million unsecured bond offering in 4Q16
- IPH liquidity excludes approximately $60 million in cash currently posted as collateral support

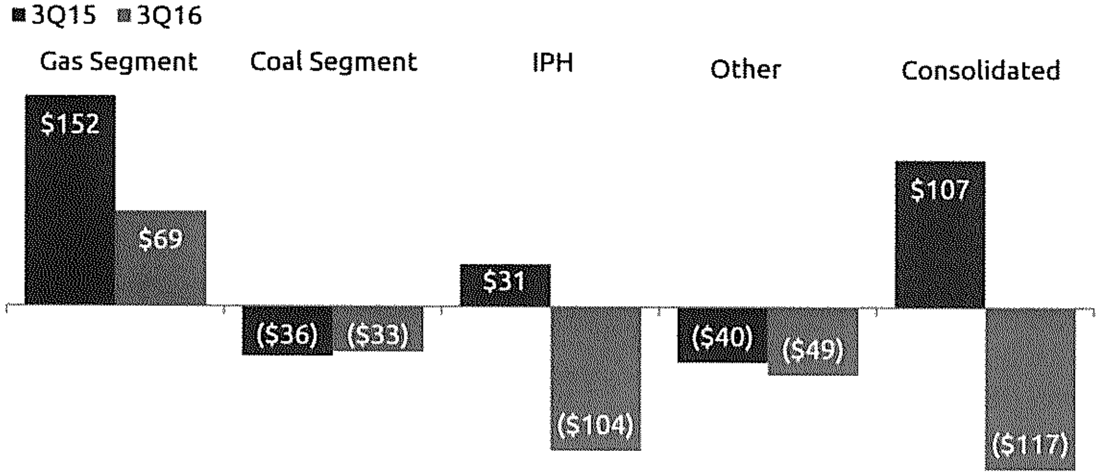
Guidance

- Affirming 2016 Adjusted EBITDA and FCF guidance
- Initiating 2017 Adjusted EBITDA and FCF guidance
  - 2017 Adjusted EBITDA range of $1,200 - 1,400 million
  - 2017 FCF range of $150 - 350 million

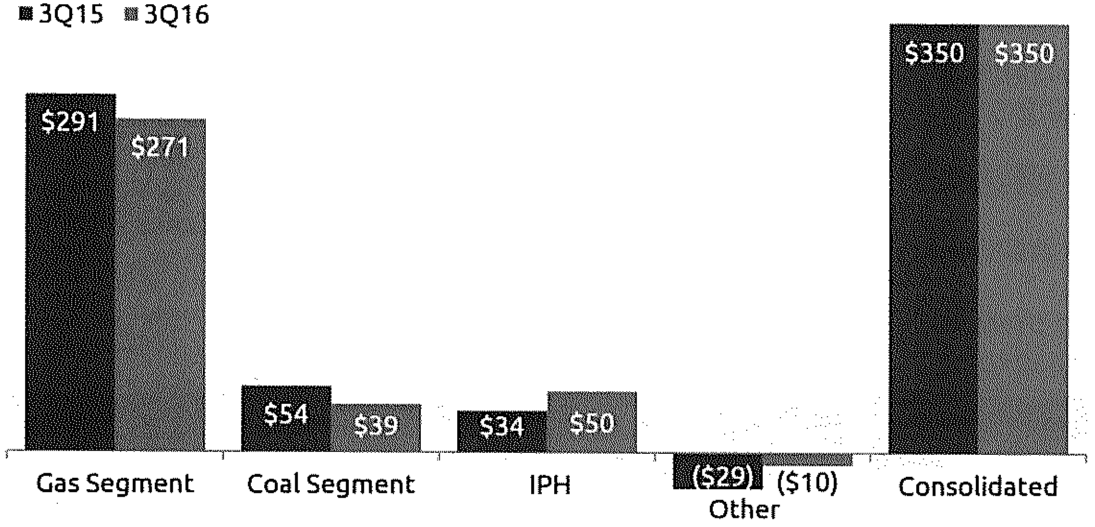
[1] See Appendix for additional detail; Note: Adjusted EBITDA and Free Cash Flow are non-GAAP measures; reconciliations to GAAP can be found in the Appendix

THIRD QUARTER PERIOD-OVER-PERIOD SEGMENT PERFORMANCE

3Q Period-over-Period Operating Income/(Loss) ($ MM)



3Q Period-over-Period Adjusted EBITDA ($ MM)



Adjusted EBITDA Changes by Source	
Gas Segment	
Realized Energy Margin	$17 MM
PJM Performance Bonus	$2 MM
Wholesale Capacity	($26) MM
O&M	($10) MM
Coal Segment	
Realized Energy Margin (excl Brayton Point below)	($6) MM
Brayton Point 3Q16 Forced Outage	($7) MM
PJM Performance Penalty (Ohio Coal Units)	($12) MM
O&M	$7 MM
IPH	
Energy Margin	$13 MM
Wholesale Capacity	$3 MM
Corporate	
Legal Resolution	$20 MM

Note: Adjusted EBITDA and Free Cash Flow are non-GAAP measures; reconciliations to GAAP can be found in the Appendix

2016 ADJUSTED EBITDA AND FREE CASH FLOW GUIDANCE

Consolidated Dynegy Inc. ($ MM)

	Affirming 2016 Guidance
Adjusted EBITDA	$1,000 – 1,100
Maintenance CapEx	($275)
Recurring Environmental CapEx	($20)
Cash Interest	($515)
Other Cash Impacts	$10
Free Cash Flow	$200 - 300

Affirming 2016 Guidance

- Guidance affirmation based on October 12, 2016 forward curves
- Forecast excludes Wood River
- Forecast includes Baldwin unit 3 and Newton unit 2
- IPH Adjusted EBITDA, before G&A allocations, estimated at $100 MM
- DI Capital Allocation (Excluded from Free Cash Flow)
  - $22 MM mandatory preferred dividends
  - $8 MM term loan amortization
  - $7 MM TEU principal paydown
  - $30 MM gas plant uprates
  - $50 MM of cash interest on ENGIE acquisition debt
  - $20 MM of OID on ENGIE acquisition term-loan debt

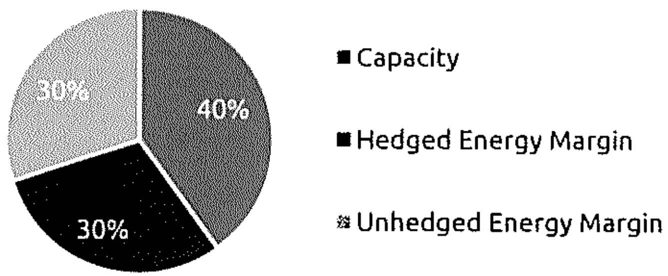
Note: Adjusted EBITDA and Free Cash Flow are non-GAAP measures; reconciliations to GAAP can be found in the Appendix

2017 ADJUSTED EBITDA AND FREE CASH FLOW GUIDANCE

Consolidated Dynegy Inc. ($ MM)

	Initiating 2017 Guidance
Adjusted EBITDA	$1,200 – 1,400
Maintenance CapEx	($450)
Recurring Environmental CapEx	($20)
Cash Interest	($625)
Other Cash Impacts	$45
Free Cash Flow	$150 - 350

2017 Gross Margin Distribution

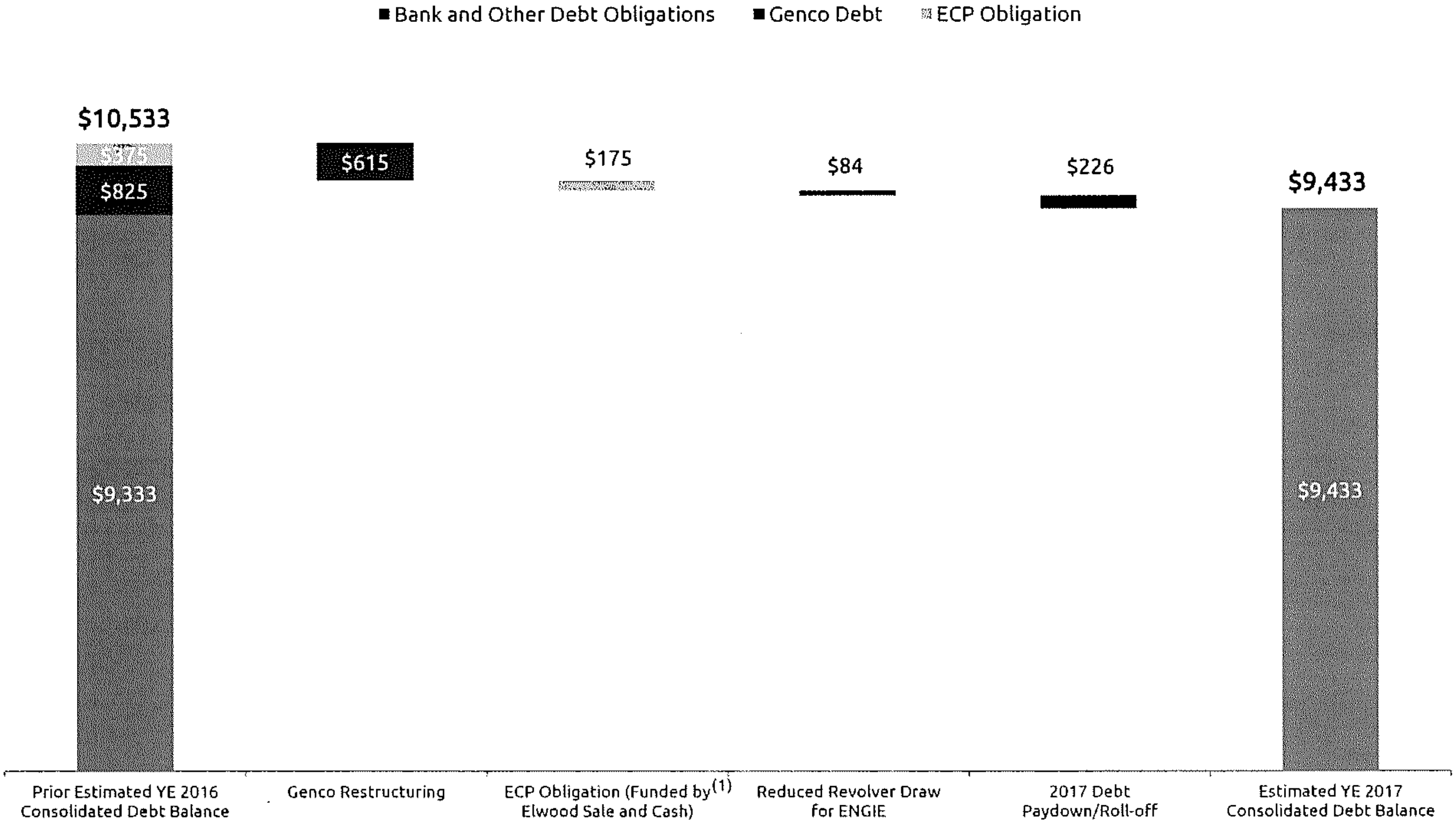


2017 Guidance Assumptions

- Guidance based on October 12, 2016 forward curves
- Assumes ENGIE closing and Elwood sale completed in 2016
- Assumes IPH restructuring completed in Q1 2017
- Assumes Moss Landing 6&7 retires year end 2016
- Approximately $40 MM in ENGIE major maintenance and capital removal reclassified to O&M to match Dynegy's capitalization policy
- Approximately $30 MM in asset shutdown costs included in O&M forecast
- 2017 forecast expected to include a high volume of outage days throughout the fleet
- Capital Allocation (Excluded from Free Cash Flow):
  - $64 MM PJM capacity monetization roll off
  - $62 MM in non-recurring environmental spend
  - $55 MM in debt paydown
  - $30 MM gas plant uprates
  - $22 MM mandatory preferred dividends
- See slide 25 for additional guidance assumptions

Note: Adjusted EBITDA and Free Cash Flow are non-GAAP measures; reconciliations to GAAP can be found in the Appendix

STRENGTHENING THE BALANCE SHEET ($ MM)

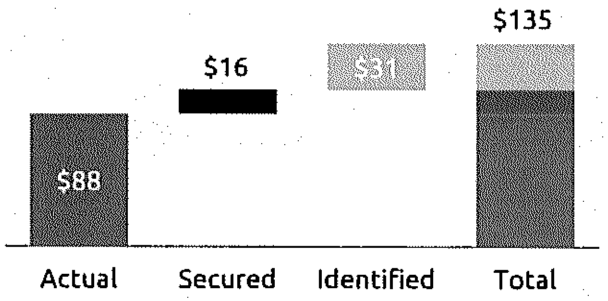


Current initiatives result in $1.1 billion of debt reduction

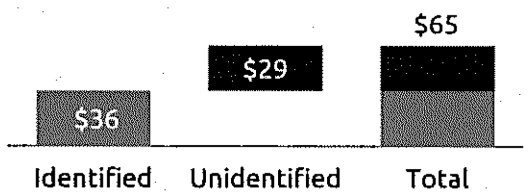
(1) Total ECP Obligation is $375 MM, $200 MM of the obligation to be funded from a portion of the October 2016 bond offering with the balance from $173 MM in proceeds from the Elwood Sale and cash on hand. **See Appendix Slide 26 for additional details**

PRIDE ENERGIZED UPDATE ($ MM)

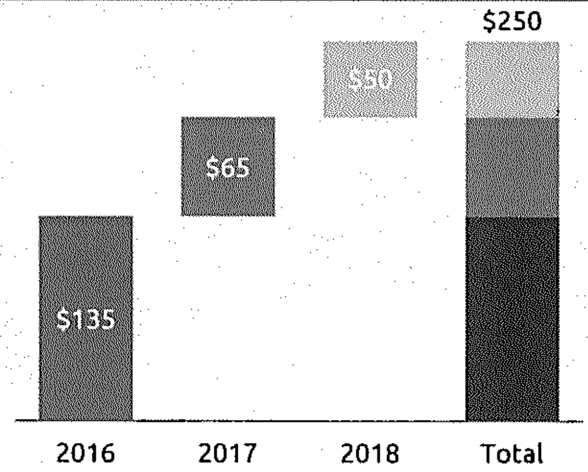
2016 PRIDE EBITDA Initiatives



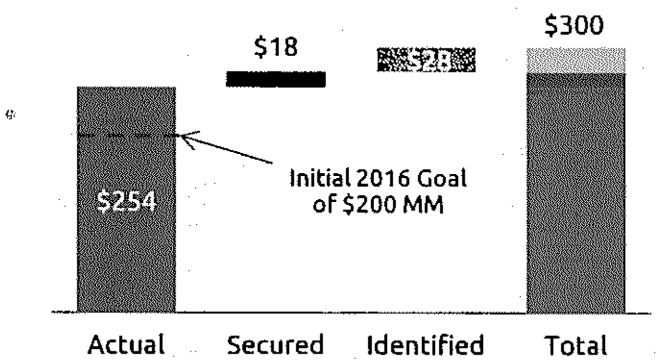
2017 PRIDE EBITDA Initiatives



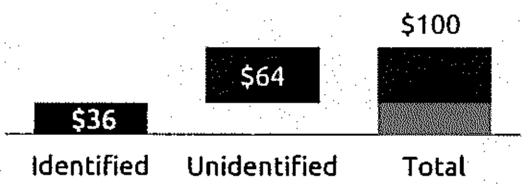
2016 - 2018 PRIDE Energized EBITDA



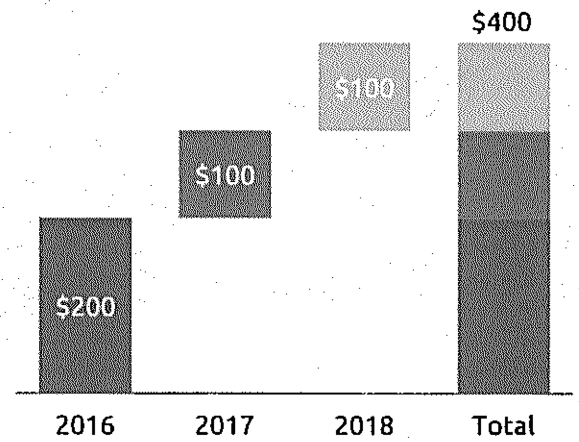
2016 PRIDE Balance Sheet Initiatives



2017 PRIDE Balance Sheet Initiatives



2016 - 2018 PRIDE Energized Balance Sheet



PRIDE Energized remains on track to meet or exceed targets

Note: Excludes ENGIE synergies

SUMMARY

ROBERT C FLEXON, PRESIDENT AND CEO

DYNEGY

KEY TAKEAWAYS

On track to achieve 2016 Adjusted EBITDA and FCF guidance targets

Genco debt restructuring remains on track

ENGIE acquisition and Elwood disposition expected in Q4 2016

PRIDE Energized goals on target for EBITDA and ahead of schedule for balance sheet

2017 Adjusted EBITDA and FCF guidance initiated at $1,200 – 1,400 MM and $150 – 350 MM, respectively

APPENDIX

DYNEGY

ADDITIONAL 2017 GUIDANCE ASSUMPTIONS

2017 Guidance Assumptions

- Assumes the following portfolio changes:
  - ENGIE closing in 2016
  - Elwood sale completed in 2016
  - IPH restructuring completed in 1Q17
  - Moss Landing 6&7 retires at year end 2016
  - Brayton Point retires at the end of May 2017
- ~$85 MM in major maintenance costs included in O&M forecast
- $11 MM in Peak Energy Rent (PER) charges in 2017
- Forecast includes adjustment for power basis as the LMP clears at an average discount to hub pricing of:
  - PJM: ~5-10%
  - MISO: ~10%
  - ISO-NE/NYISO: ~0-5%

2017 Hedge Detail Including ENGIE (MM MWhrs)

	Generation	Hedge %	Open Volumes
Coal	40	58%	17
Gas	78	38%	48
IPH	20	55%	9
Total	138	46%	74
Current DYN	103	62%	39
ENGIE	35	0%	35
Total	138	46%	74

2017 Forecasted Outage Days (Outages > 20 days)

	Q1	Q2	Q3	Q4
Conesville				65
Kincaid		37		
Liberty GT2		24		
Stuart 1	58			
Stuart 2		37		
Stuart 4				51
Milford GT1/ ST1	35			
Milford GT2/ ST2		31		
Moss Landing 1&2	46			
Hennepin 2			56	
Coffeen 1			88	
Edwards 2				56
Joppa 1				42
ENGIE-PJM		21		
ENGIE-ISO-NE	35	35		
ENGIE-ERCOT	35	35	24	

ADDITIONAL 2017 GUIDANCE ASSUMPTIONS (CONTINUED)

Debt and Other Financing Obligations[1] ($ MM)	
Estimated Dec 2016 Dynegy Inc. Debt Balance at 2Q16	$9,333
ECP Obligation	$375
IPH Debt	$825
Total Estimated Dec 2016 Debt/Obligations Balance at 2Q16	**$10,533**
Changes to Dec 2016 Debt/Obligation Estimates since 2Q16:	
Genco Debt Restructuring	($615)
October 2016 Bond Offering	$750
ECP Payment	($375)
Paydown of Debt	($550)
Reduction to Expected Revolver Draw for ENGIE	($84)
Total Change in Debt/Obligations from 2Q16 Estimate	($874)
Total Estimated Dec 2016 Debt/Obligations	**$9,659**
2017 Reductions to Debt:	
Term Loan Amortization[2]	($28)
Tangible Equity Units[2]	($27)
Forward Capacity Agreement[2]	($64)
Emissions Inventory Financing[3]	($30)
Coal Inventory Financing[3]	($57)
Equipment Financing[4]	($20)
Total 2017 Debt Reductions	($226)
Total Estimated Dec 2017 Debt/Obligations	**$9,433**

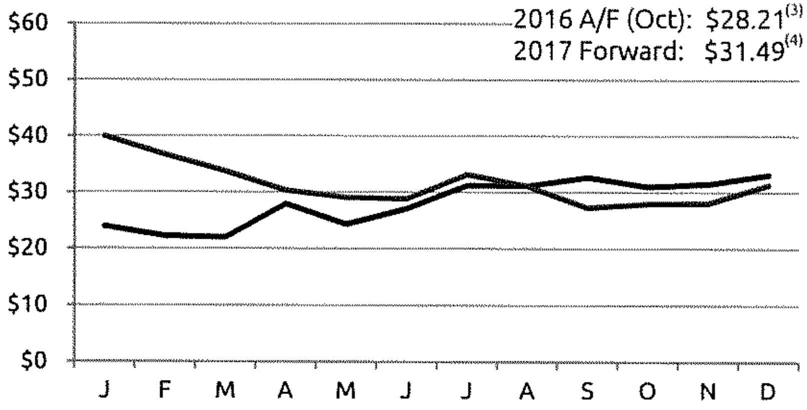
[1] Excludes any voluntary prepayments of debt in 2017; [2] Obligation met using free cash flow; [3] Cost captured in forecasted gross margin; [4] Cost captured in forecasted LTSA CapEx

Ex. TC - 4

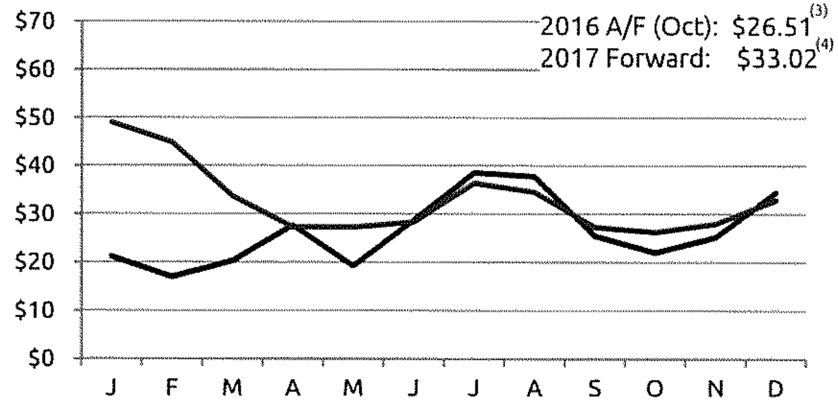
COMMODITY PRICING AROUND-THE-CLOCK POWER (OCT 12 PRICING)

2016 A/F (Oct)[1] 2017 Forward[2]

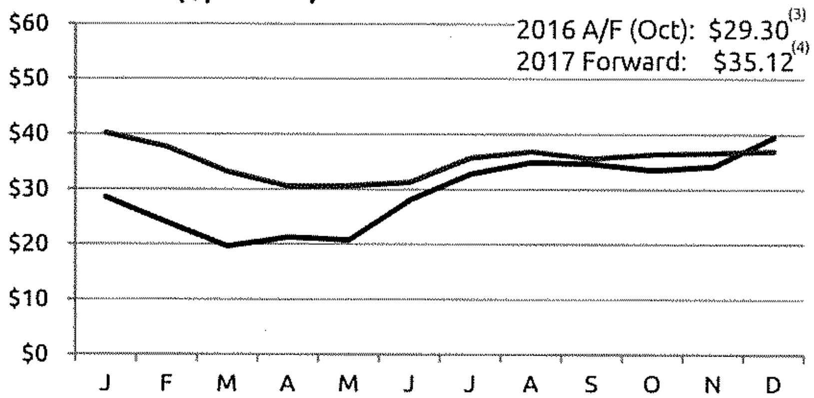
Indiana Hub ($/MWh)



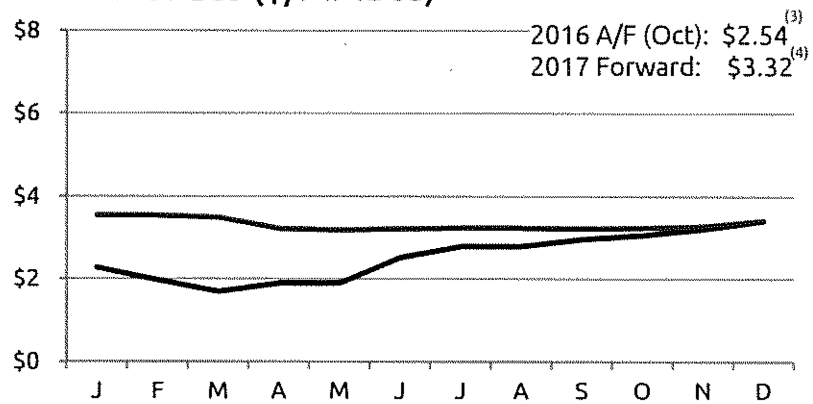
New York Zone A ($/MWh)



NP-15 ($/MWh)



Natural Gas ($/MMBtu)

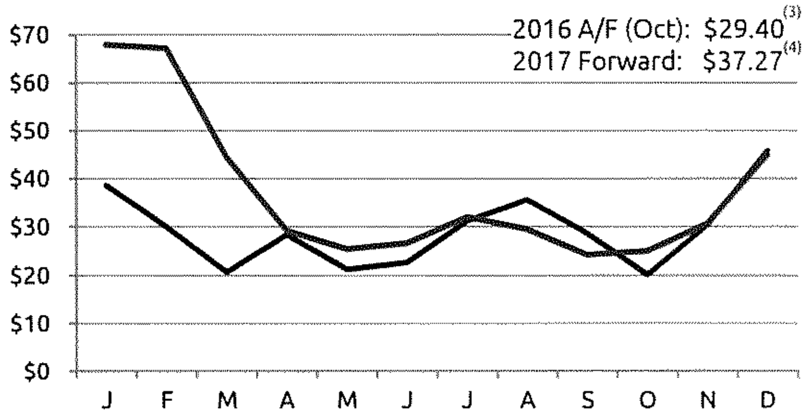


(1) Prices reflect actual day ahead ATC settlement prices for 1/1/2016 -10/12/2016 and quoted forward ATC monthly prices for 10/13/2016 -12/31/2016. (2) Prices reflect quoted forward ATC monthly prices for 2017. (3) Single price provided reflects full year estimated ATC price for 2016 using a mix of 2016 actuals through October 12, 2016 and 2016 forward monthly prices for the balance of the year based on October 12, 2016 pricing. (4) Single price provided reflects full year estimated ATC price for 2017 using a monthly average based on October 12, 2016 pricing

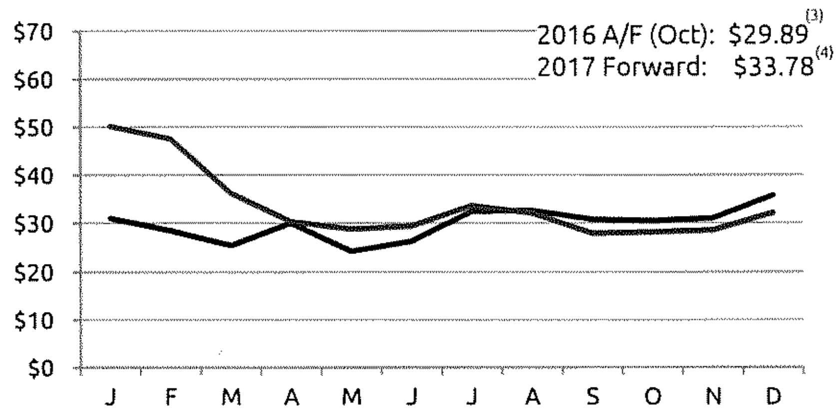
COMMODITY PRICING AROUND-THE-CLOCK POWER (OCT 12 PRICING) (CONTINUED)

2016 A/F (Oct)[1] 2017 Forward[2]

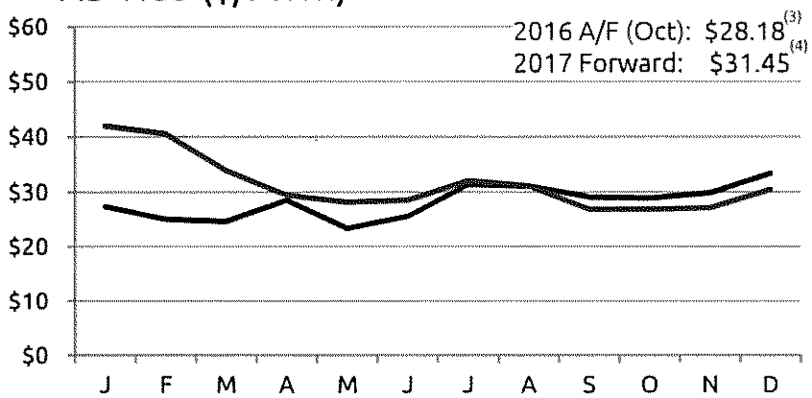
Mass Hub ($/MWh)



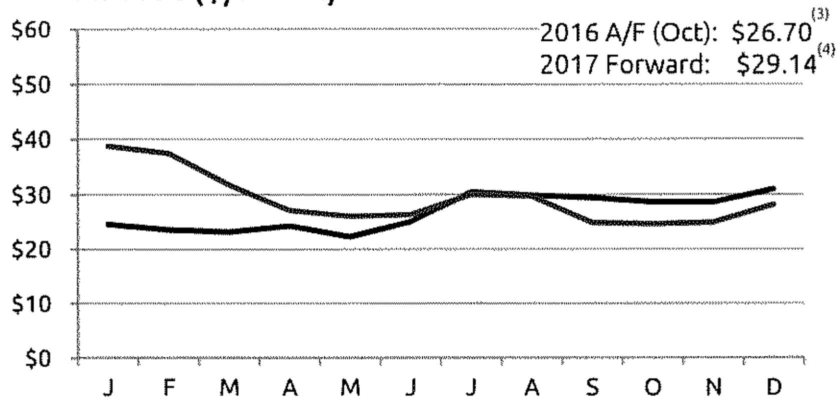
PJM-W ($/MWh)



AD-Hub ($/MWh)



Ni-Hub($/MWh)

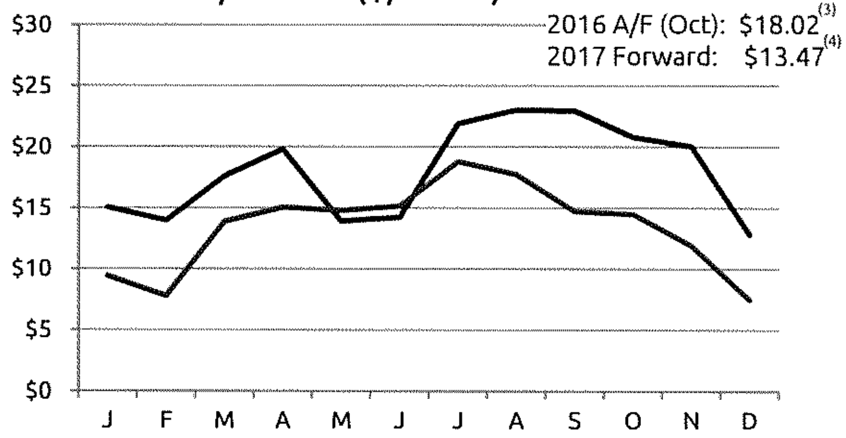


(1) Prices reflect actual day ahead ATC settlement prices for 1/1/2016 -10/12/2016 and quoted forward ATC monthly prices for 10/13/2016 -12/31/2016. (2) Prices reflect quoted forward ATC monthly prices for 2017. (3) Single price provided reflects full year estimated ATC price for 2016 using a mix of 2016 actuals through October 12, 2016 and 2016 forward monthly prices for the balance of the year based on October 12, 2016 pricing. (4) Single price provided reflects full year estimated ATC price for 2017 using a monthly average based on October 12, 2016 pricing

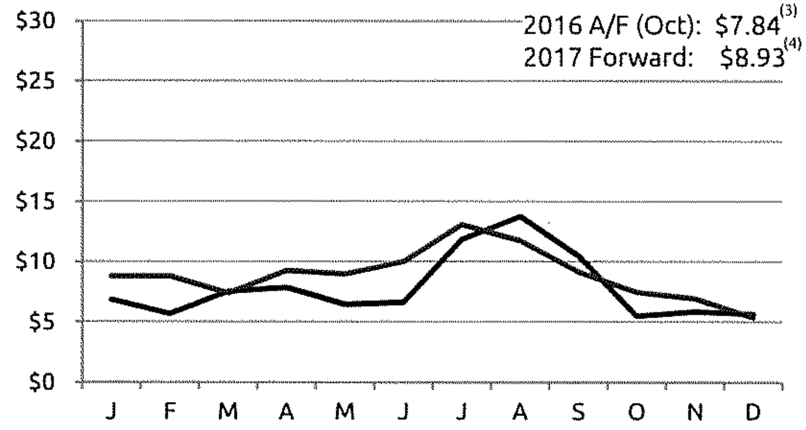
SPARK SPREADS AROUND-THE-CLOCK (OCT 12 PRICING)

2016 A/F (Oct)[1] 2017 Forward[2]

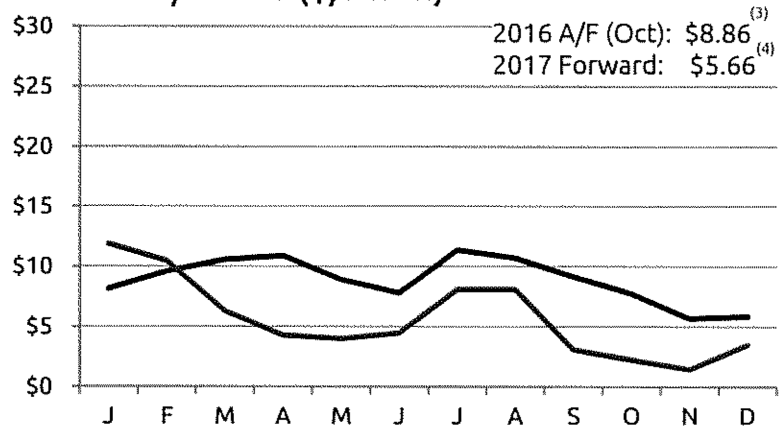
PJM West/TetM3 ($/MWh)



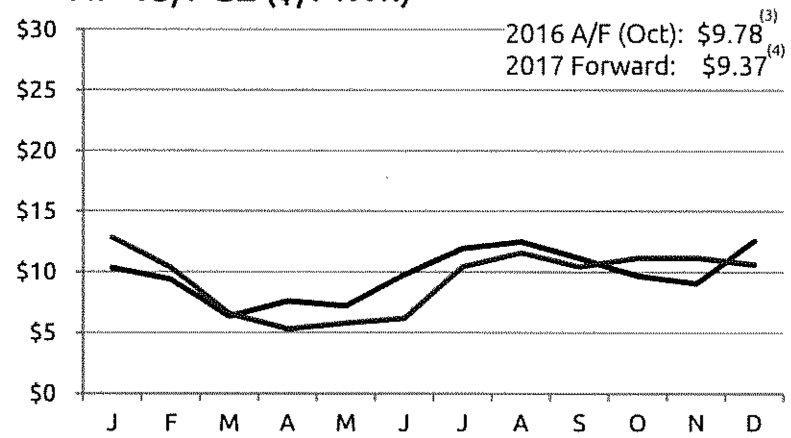
Mass Hub/Algonquin ($/MWh)



Ni-Hub/ChiCG ($/MWh)

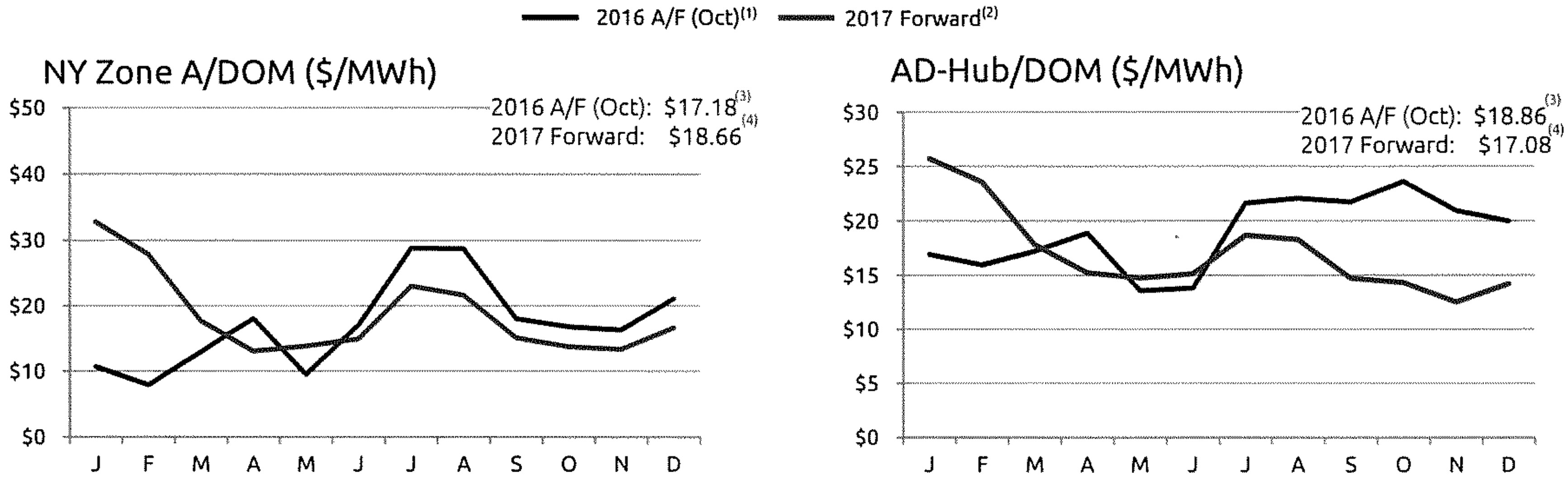


NP-15/PGE ($/MWh)



[1] Prices reflect actual day ahead ATC settlement prices for 1/1/2016-10/12/2016 and quoted forward ATC monthly prices for 10/13/2016-12/31/2016. [2] Prices reflect quoted forward ATC monthly prices for 2017. [3] Single price provided reflects full year estimated ATC price for 2016 using a mix of 2016 actuals through October 12, 2016 and 2016 forward monthly prices for the balance of the year based on October 12, 2016 pricing. [4] Single price provided reflects full year estimated ATC price for 2017 using a monthly average based on October 12, 2016 pricing

SPARK SPREADS AROUND-THE-CLOCK (OCT 12 PRICING) (CONTINUED)



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DYNEGY GAS-FUELED GENERATION FACILITIES (as of 9/30/2016)

Portfolio/Facility[1]	Location	Net Capacity[2]	Primary Fuel	Dispatch Type	Market Region
Gas Segment					
Casco Bay	Veazie, ME	538	Gas – CCGT	Intermediate	ISO-NE
Milford	Milford, CT	569	Gas – CCGT	Intermediate	ISO-NE
Lake Road	Dayville, CT	857	Gas – CCGT	Intermediate	ISO-NE
Dighton	Dighton, MA	185	Gas – CCGT	Intermediate	ISO-NE
MASSPOWER	Indian Orchard, MA	280	Gas – CCGT	Intermediate	ISO-NE
Independence	Oswego, NY	1,156	Gas – CCGT	Intermediate	NYISO
Kendall	Minooka, IL	1,288	Gas – CCGT	Intermediate	PJM
Ontelaunee	Reading, PA	640	Gas – CCGT	Intermediate	PJM
Hanging Rock	Ironton, OH	1,430	Gas – CCGT	Intermediate	PJM
Washington	Beverly, OH	711	Gas – CCGT	Intermediate	PJM
Fayette	Masontown, PA	726	Gas – CCGT	Intermediate	PJM
Liberty	Eddystone, PA	589	Gas – CCGT	Intermediate	PJM
Dicks Creek	Monroe, OH	155	Gas – CT	Peaking	PJM
Lee	Dixon, IL	787	Gas – CT	Peaking	PJM
Elwood*[3]	Elwood, IL	790	Gas – CT	Peaking	PJM
Richland	Defiance, OH	423	Gas – CT	Peaking	PJM
Stryker	Stryker, OH	16	Oil – CT	Peaking	PJM
Moss Landing	Moss Landing, CA				
Units 1-2		1,020	Gas – CCGT	Intermediate	CAISO
Units 6-7[4]		1,509	Gas – CT	Peaking	CAISO
Oakland	Oakland, CA	165	Oil – CT	Peaking	CAISO
Gas Segment Total		**13,834**			

NOTES:

1) Dynegy owns 100% of each unit listed except for those marked by an asterisk (*). Total Net Capacity set forth in this table for partially owned units includes only Dynegy's proportionate share of that facility's gross generating capacity
2) Unit capabilities are based on winter capacity ratings
3) Dynegy to sell its interest in the Elwood Energy Facility with closing expected in 4Q16
4) Dynegy announced its intention to retire Moss Landing 6&7 in 2017

DYNEGY COAL-FUELED GENERATION FACILITIES (as of 9/30/2016)

Portfolio/Facility[1]	*Location*	*Net Capacity[2]*	*Primary Fuel*	*Dispatch Type*	*Market Region*
Coal Segment					
Baldwin[3]	Baldwin, IL	1,815	Coal	Baseload	MISO
Havana	Havana, IL	434	Coal	Baseload	MISO
Hennepin[4]	Hennepin, IL	294	Coal	Baseload	MISO
Stuart*	Aberdeen, OH	904	Coal	Baseload	PJM
Miami Fort 7&8*	North Bend, OH	653	Coal	Baseload	PJM
Miami Fort CT	North Bend, OH	77	Oil – CT	Peaking	PJM
Zimmer*	Moscow, OH	628	Coal	Baseload	PJM
Conesville*	Conesville, OH	312	Coal	Baseload	PJM
Killen*	Manchester, OH	204	Coal	Baseload	PJM
Kincaid	Kincaid, IL	1,108	Coal	Baseload	PJM
Brayton Point	Somerset, MA	1,488	Coal	Baseload	ISO-NE
Coal Segment Total		7,917			
IPH					
Coffeen	Coffeen, IL	915	Coal	Baseload	MISO/PJM
Joppa*[4][5]	Joppa, IL	802	Coal	Baseload	MISO
Joppa CT 1-3[5]	Joppa, IL	165	Gas – CT	Peaking	MISO
Joppa CT 4-5*[5]	Joppa, IL	56	Gas – CT	Peaking	MISO
Newton	Newton, IL	615	Coal	Baseload	MISO/PJM
Duck Creek	Canton, IL	425	Coal	Baseload	MISO/PJM
E.D. Edwards	Bartonville, IL	585	Coal	Baseload	MISO/PJM
IPH Total		3,563			
TOTAL GENERATION		25,314			

NOTES:

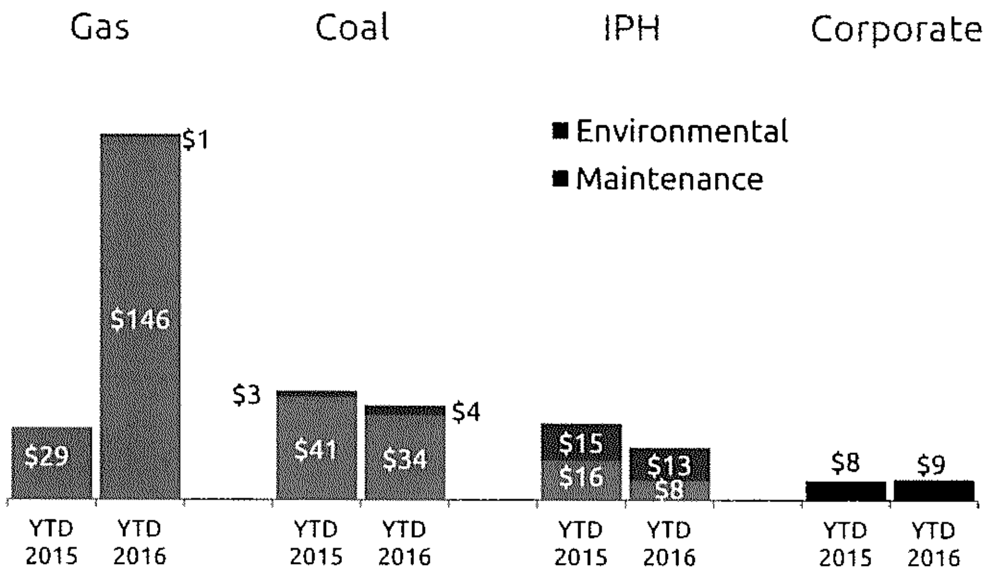
1) Dynegy owns 100% of each unit listed except for those marked by an asterisk (*). Total Net Capacity set forth in this table for partially owned units includes only Dynegy's proportionate share of that facility's gross generating capacity
2) Unit capabilities are based on winter capacity ratings
3) Includes 630 MW of capacity mothballed in October 2016
4) A portion of this facility's capacity is scheduled to move to PJM beginning June 1, 2017
5) Not located within MISO

Assets in Multiple Markets
(Net Capacity by ISO)

	MISO	PJM
Coffeen	764	151
Newton	308	307
Duck Creek	96	329
Edwards	435	150

CAPITAL AND MAJOR MAINTENANCE O&M EXPENDITURES YEAR-OVER-YEAR

Capital Expenditures by Segment[1][2] ($ MM)



Coal Segment

- Capital spending decreased due to fewer planned outages

Gas Segment

- Capital spending increased due to a larger number of planned major outages

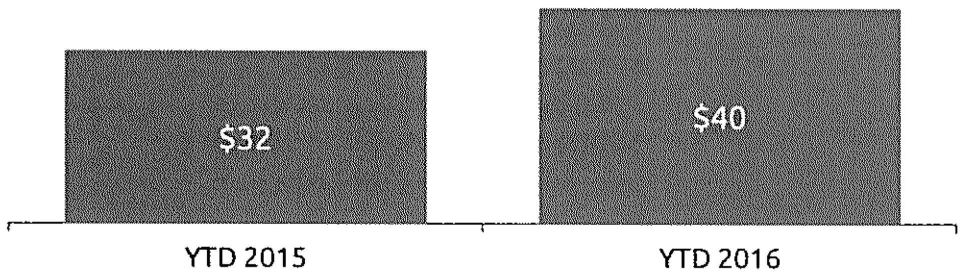
IPH

- Capital spending reduced due to fewer planned outages and cancellation of Newton scrubber project

Corporate

- Capital spending remained relatively flat year-over-year

Total Major Maintenance Expense ($ MM)



Coal, Gas, and IPH Segments

- Increase in maintenance expense mostly due to increased number of planned major outages in the Gas segment
- Major maintenance was partially offset with fewer planned outages at IPH

(1) Excludes capitalized interest; (2) Excludes discretionary investments for growth and reliability

DEBT, LIQUIDITY, AND RING-FENCING (as of 9/30/2016)

Dynegy Inc.[1]

$774 MM Term Loan
$500 MM in 5.875% Senior Notes
$2.1 BN in 6.75% Senior Notes
$1.75 BN in 7.375% Senior Notes
$1.25 BN in 7.625% Senior Notes
$87 MM in 7.00% Amortizing Notes (TEUs)

Dynegy Finance IV Inc.

$2.0 BN Tranche C Term Loan

DI Available Liquidity ($ MM)	
Cash and Equivalents	$1,351
Revolver & LC Capacity	*$1,480*
Outstanding LCs	*($382)*
Revolver Availability	$1,098
Total DI Liquidity	**$2,449**

Ring-fencing

IPH

Illinois Power Resources Generating (IPRG)
585 MW Edwards
425 MW Duck Creek

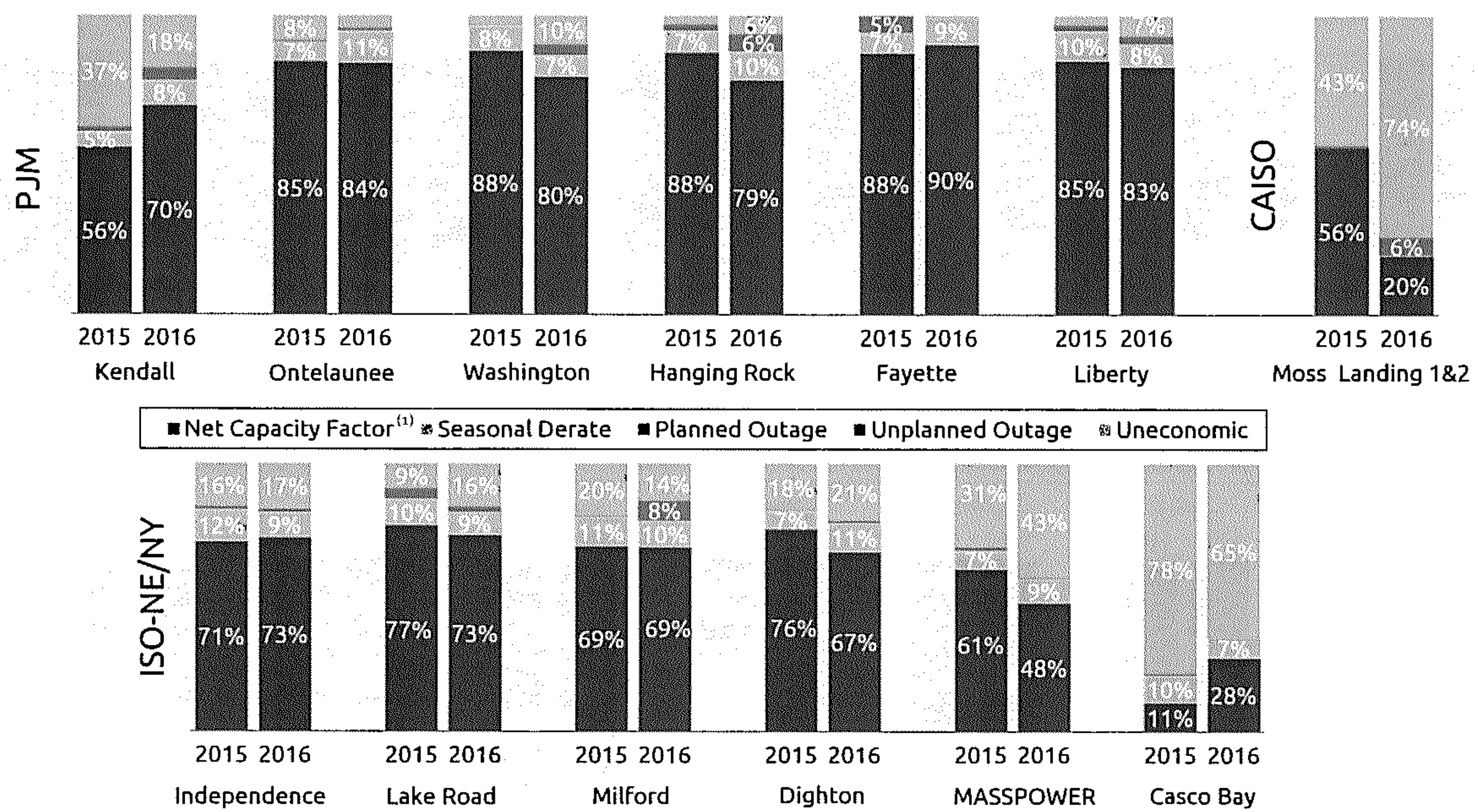
Illinois Power Marketing Company (IPM)

Illinois Power Generating Company (Genco)
$825 MM of Senior Notes[4]
615 MW Newton • 915 MW Coffeen • 1,023 MW Joppa[2]

IPH Available Liquidity ($ MM)	
Cash and Equivalents[3]	$107
Revolver & LC Capacity	*$44*
Outstanding LCs	*($30)*
Revolver Availability	$14
Total IPH Liquidity	**$121**

[1] Excludes $76 MM of nonrecourse Elwood senior notes and $750 MM of 8.00% senior notes due 2025, secured in October 2016; [2] Reflects 80% stake; [3] Genco cash of $84 MM; [4] On October 3, 2016, Dynegy announced that it had reached a deal in principle with an ad hoc group of Genco bondholders to restructure the Genco notes

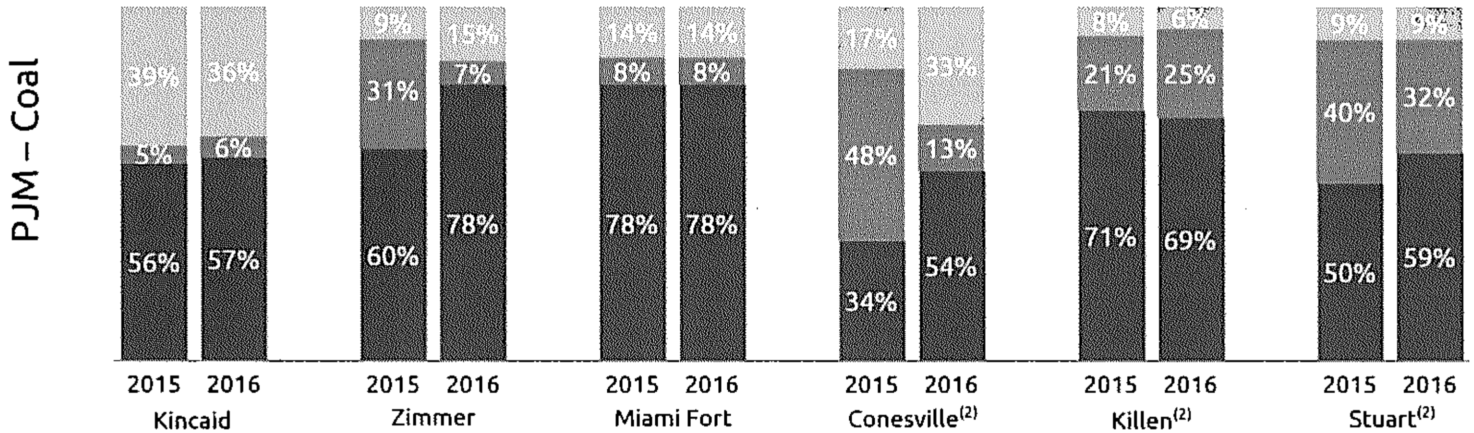
THIRD QUARTER FLEET PERFORMANCE – GAS SEGMENT

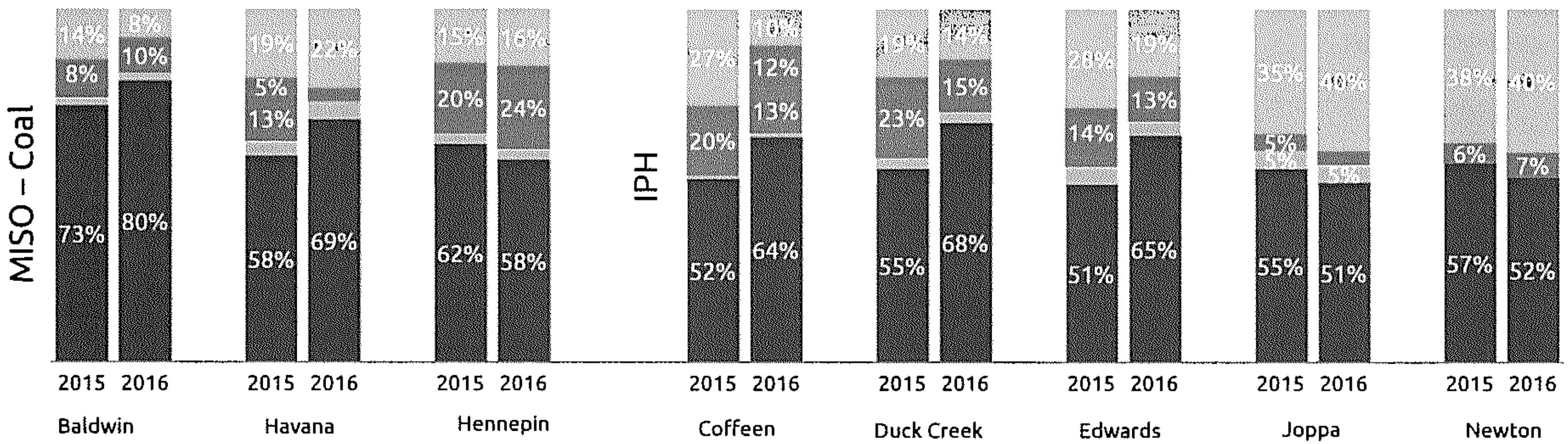


Gas fleet continues strong reliability performance in a low gas price environment

(1) Net Capacity Factor is based on the NERC method of calculation, which uses a maximum capacity rating

THIRD QUARTER FLEET PERFORMANCE – COAL SEGMENT & IPH





Higher prices in MISO and increased reliability improved capacity factors

(1) Net Capacity Factor is based on the NERC method of calculation, which uses a maximum capacity rating; (2) Jointly owned facilities not operated by Dynegy

OPERATIONAL STATISTICS

Gas Segment - Combined Cycle	3Q15	3Q16	YTD 2015	YTD 2016
Total Generation (MM MWh)				
California	1.3	0.5	2.4	1.8
NY/NE	4.9	5.0	10.7	11.6
PJM	8.9	9.3	19.4	26.0
In-Market-Availability				
California	99.7%	91.7%	96.0%	95.9%
NY/NE	98.8%	98.2%	97.6%	95.2%
PJM	99.0%	96.9%	98.9%	97.4%
Average Capacity Factor[1]				
California	56.2%	20.0%	36.6%	27.1%
NY/NE	64.5%	63.2%	56.6%	49.7%
PJM	81.3%	79.4%	75.1%	74.7%

[1] Average Capacity Factor is based on the NERC method of calculation, which uses a maximum capacity rating

OPERATIONAL STATISTICS , CONT.

Coal Segment[1]	3Q15	3Q16	YTD 2015	YTD 2016
Total Generation (MM MWh)				
MISO	4.5	4.2	12.9	11.2
PJM	4.7	5.4	8.4	12.6
Brayton Point	0.3	0.4	0.4	1.5
In-Market-Availability				
MISO	90.6%	89.8%	87.2%	88.7%
PJM	76.5%	83.3%	73.4%	80.8%
Brayton Point	90.3%	75.0%	91.2%	87.5%
Average Capacity Factor[2]				
MISO	68.3%	75.6%	65.7%	60.9%
PJM	57.4%	64.8%	51.1%	51.3%
Brayton Point	9.2%	13.0%	5.5%	15.1%

IPH[1]	3Q15	3Q16	YTD 2015	YTD 2016
Total Generation (MM MWh)	4.8	5.0	14.7	11.6
In-Market-Availability	84.2%	87.5%	89.0%	88.2%
Average Capacity Factor[2]	54.1%	58.5%	55.5%	45.0%

(1) In-Market Availability and Average Capacity Factor do not include CTs; (2) Average Capacity Factor is based on the NERC method of calculation, which uses a maximum capacity rating

MARKET PRICING

Average Actual Power/Gas Prices ($/MWh)

	3Q15		3Q16		YTD 15		YTD 16	
	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Henry Hub ($/MMBtu)	$2.74		$2.84		$2.78		$2.31	
Indy Hub	$33.09	$23.37	$40.19	$24.38	$35.17	$25.41	$32.32	$22.31
Mass Hub	$35.52	$21.02	$41.31	$23.57	$53.62	$38.90	$34.44	$23.40
NP-15	$38.32	$30.28	$37.70	$29.57	$36.20	$29.32	$29.92	$23.64
NY - Zone A	$34.92	$19.08	$48.02	$21.99	$40.47	$25.10	$36.02	$17.69
PJM-W	$39.14	$24.82	$40.74	$24.36	$46.61	$31.74	$34.77	$24.08
AD Hub	$35.87	$24.21	$38.75	$23.53	$39.86	$27.20	$32.66	$22.72
NiHub	$34.03	$22.93	$38.41	$22.57	$35.44	$23.49	$31.54	$20.81

Average Trading Hub Spark Spreads ($/MWh)

	3Q15		3Q16		YTD 15		YTD 16	
	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
PJM West/TetM3	$29.82	$15.50	$31.48	$15.10	$25.58	$10.71	$23.79	$13.10
NiHub/ChiCG	$14.49	$3.39	$18.93	$3.09	$14.91	$2.97	$15.41	$4.68
NP-15/PGE	$16.25	$8.22	$15.44	$7.31	$14.63	$7.75	$12.32	$6.03
NY-Zone A/Dominion	$26.32	$10.49	$39.27	$13.24	$29.49	$14.12	$26.66	$8.32
Mass Hub/Algonquin	$18.90	$4.39	$21.58	$3.85	$15.77	$1.05	$14.49	$3.46
AD Hub/Dominion	$23.17	$15.62	$27.27	$14.78	$34.41	$16.22	$28.88	$13.36

PJM CAPACITY POSITION (includes MISO imports)

PJM Region	Planning Year	Average Price ($/MW-day)	MW Position	Average Price ($/MW-day)	MW Position
		Legacy/Base Product		Capacity Performance Product	
RTO	2016-2017	$81.53	1,213	$134.00	3,992
	2017-2018	$112.86	2,698	$151.50	3,207
	2018-2019	$155.74	1,659	$164.77	3,905
	2019-2020	$80.00	1,616	$100.00	3,452
ComEd	2016-2017	$66.98	707	$134.00	2,447
	2017-2018	$120.63	1,248	$151.50	2,261
	2018-2019	$200.21	0	$215.21	3,112
	2019-2020	$182.77	0	$202.77	3,462
MAAC	2016-2017	$119.13	453	$134.00	51
	2017-2018	$120.00	0	$151.50	508
	2018-2019	$149.98	0	$166.82	508
	2019-2020	$80.00	0	$127.21	515
EMAAC	2016-2017	$119.53	485	$134.00	53
	2017-2018	$120.00	8	$151.50	533
	2018-2019	$210.63	0	$225.42	532
	2019-2020	$99.77	0	$119.77	534
ATSI	2016-2017	$115.75	361	$134.00	0
	2017-2018	$121.65	374	$151.50	0
	2018-2019	$149.98	0	$164.77	195
	2019-2020	$80.00	0	$100.00	224

Note: PJM capacity position represent volumes cleared and purchased in primary annual auctions, incremental auctions, and transitional auctions. Also includes bilateral transactions

ISO-NE / NYISO / CAISO CAPACITY POSITIONS

Capacity / Resource Adequacy

ISO/Region	Contract Type	Average Price	Size (MW)	Tenor
ISO-NE[1]	ISO-NE Capacity	$3.24/kw-Mo	3,683	June 2016 to May 2017
		$6.99/kw-Mo	2,186	June 2017 to May 2018
		$9.64/kw-Mo	2,195	June 2018 to May 2019
		$7.03/kw-Mo	2,240	June 2019 to May 2020
NYISO[2][3]	NYISO Capacity	$3.36/kw-Mo	927	Summer 2016
		$2.47/kw-Mo	839	Winter 2016/2017
		$3.44/kw-Mo	868	Summer 2017
		$3.14/kw-Mo	580	Winter 2017/18
		$3.66/kw-Mo	565	Summer 2018
		$3.32/kw-Mo	330	Winter 2018/2019
		$3.39/kw-Mo	255	Summer 2019
CAISO[4]	RA Capacity		801	Avg Bilateral Sold Q3 2016
			230	Avg Bilateral Sold Q4 2016
			725	Avg Bilateral Sold Cal 2017
			400	Avg Bilateral Sold Cal 2018
			850	Avg Bilateral Sold Cal 2019

[1] ISO-NE represents capacity auctions results, supplemental auctions and bilateral capacity sales; [2] NYISO represents capacity auction results and bilateral capacity sales; [3] Winter period covers November through April and the Summer period covers May through October; [4] Dynegy is prohibited from disclosing RA capacity sales through 2016 at Moss Landing 6&7

MISO CAPACITY POSITION (excludes PJM exports)

Price in $/kw-mo	Coal Segment	IPH	Total	EBITDA Contribution
PY 16/17				
MWs	1,011	2,246	3,257	
Average Price	$2.75	$4.30	$3.81	$149 MM
PY 17/18				
MWs	1,075	1,899	2,974	
Average Price	$3.39	$4.63	$4.18	$149 MM
PY 18/19				
MWs	242	1,518	1,760	
Average Price	$2.68	$5.12	$4.79	$101 MM
PY 19/20				
MWs	185	570	755	
Average Price	$2.60	$5.20	$4.56	$42 MM
Total MWs	2,513	6,233	8,746	
Average Price	$3.00	$4.68	$4.20	$441 MM

Capacity Updates

- MISO planning year 2016/2017 cleared at $72/MW-day with Dynegy clearing no incremental MW beyond its Wholesale/Retail obligations
- Removal of Wood River from open position
- Addition of Joppa CTs to open position
- Removal of shutdowns from open position beginning planning year 2017/2018 (Newton Unit 2 and Baldwin Unit 3)
- In Q3 2016, Dynegy was notified that it was a winning bidder for the Illinois Power Authority procurement of capacity

Remaining Open Capacity Could Contribute to EBITDA Increase

- ~4 GW of MISO capacity remains available to sell for Planning Years 2017/2018 – 2019/2020[1]

~43% of MISO capacity remains available for sale through PY 2019/2020[2]

[1] Load Serving Entities in MISO must have their capacity requirements met for Planning Year 2016/2017 by conclusion of the auction, so Planning Year 2017/2018 is the next period for which Load Serving Entities must procure capacity; [2] Assumes ~3,100 MW per planning year over PY 2017/2018 – PY 2019/2020

APPENDIX

REG G RECONCILIATIONS

DYNEGY

REG G RECONCILIATION – 3RD QUARTER 2015 ADJUSTED EBITDA

DYNEGY INC.
REPORTED SEGMENTED RESULTS OF OPERATIONS
THREE MONTHS ENDED SEPTEMBER 30, 2015
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the three months ended September 30, 2015:

	Three Months Ended September 30, 2015				
	Coal	IPH	Gas	Other	Total
Net loss attributable to Dynegy Inc.					$ (24)
Plus / (Less):					
Income tax expense					28
Interest expense					145
Depreciation and amortization expense					176
EBITDA (1)	$ (6)	$ 37	$ 287	$ 7	$ 325
Plus / (Less):					
Adjustment to reflect Adjusted EBITDA from unconsolidated investment	—	—	8	—	8
Acquisition and integration costs	—	—	—	8	8
Mark-to-market adjustments, including warrants	(14)	(3)	(6)	(45)	(68)
Impairments	74	—	—	—	74
Other	—	—	2	1	3
Adjusted EBITDA (1)(2)	$ 54	$ 34	$ 291	$ (29)	$ 350

(1) EBITDA and Adjusted EBITDA are non-GAAP financial measures. Please refer to Item 2.02 of our Form 8-K filed on November 1, 2016, for definitions, utility and uses of such non-GAAP financial measures. A reconciliation of EBITDA to Operating income (loss) is presented below. Management does not allocate interest expense and income taxes on a segment level and therefore uses Operating income (loss) as the most directly comparable GAAP measure.

(2) Not adjusted for these items which are excluded in 2016: (i) non-cash compensation expense of $6 million, and (ii) Wood River's energy margin and O&M costs of $1 million.

	Three Months Ended September 30, 2015				
	Coal	IPH	Gas	Other	Total
Operating income (loss)	$ (36)	$ 31	$ 152	$ (40)	$ 107
Depreciation and amortization expense	30	6	139	1	176
Losses from unconsolidated investment	—	—	(4)	—	(4)
Other income and expense, net	—	—	—	46	46
EBITDA	$ (6)	$ 37	$ 287	$ 7	$ 325

REG G RECONCILIATION – 3RD QUARTER 2016 ADJUSTED EBITDA

DYNEGY INC.
REPORTED SEGMENTED RESULTS OF OPERATIONS
THREE MONTHS ENDED SEPTEMBER 30, 2016
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the three months ended September 30, 2016:

	Three Months Ended September 30, 2016				
	Coal	**IPH**	**Gas**	**Other**	**Total**
Net loss attributable to Dynegy Inc.					$ (249)
Plus / (Less):					
Income tax benefit					(1)
Interest expense					166
Depreciation and amortization expense					175
EBITDA (1)	$ —	$ (96)	$ 210	$ (23)	$ 91
Adjustments to reflect Adjusted EBITDA from unconsolidated investment and exclude noncontrolling interest	—	(1)	(4)	—	(5)
Acquisition, integration and restructuring costs	—	—	—	12	12
Mark-to-market adjustments, including warrants	(20)	2	53	(4)	31
Impairments	55	148	9	—	212
Wood River energy margin and O&M	3	—	—	—	3
Non-cash compensation expense	—	—	1	5	6
Other	1	(3)	2	—	—
Adjusted EBITDA (1)	$ 39	$ 50	$ 271	$ (10)	$ 350

(1) EBITDA and Adjusted EBITDA are non-GAAP financial measures. Please refer to Item 2.02 of our Form 8-K filed on November 1, 2016, for definitions, utility and uses of such non-GAAP financial measures. A reconciliation of EBITDA to Operating income (loss) is presented below. Management does not allocate interest expense and income taxes on a segment level and therefore uses Operating income (loss) as the most directly comparable GAAP measure.

	Three Months Ended September 30, 2016				
	Coal	**IPH**	**Gas**	**Other**	**Total**
Operating income (loss)	$ (33)	$ (104)	$ 69	$ (49)	$ (117)
Depreciation and amortization expense	30	7	137	1	175
Earnings from unconsolidated investment	—	—	4	—	4
Other income and expense, net	3	1	—	25	29
EBITDA	$ —	$ (96)	$ 210	$ (23)	$ 91

REG G RECONCILIATION – PRIOR YEAR-TO-DATE ADJUSTED EBITDA

DYNEGY INC.
REPORTED SEGMENTED RESULTS OF OPERATIONS
NINE MONTHS ENDED SEPTEMBER 30, 2015
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the nine months ended September 30, 2015:

	Nine Months Ended September 30, 2015				
	Coal	**IPH**	**Gas**	**Other**	**Total**
Net income attributable to Dynegy Inc.					$ 184
Plus / (Less):					
Loss attributable to noncontrolling interest					(3)
Income tax benefit					(473)
Interest expense					413
Depreciation and amortization expense					414
EBITDA (1)	$ 44	$ 66	$ 595	$ (170)	$ 535
Plus / (Less):					
Adjustments to reflect Adjusted EBITDA from unconsolidated investment and exclude noncontrolling interest	—	3	8	—	11
Acquisition and integration costs	—	—	—	121	121
Mark-to-market adjustments, including warrants	(35)	(8)	(29)	(43)	(115)
Impairments	74	—	—	—	74
Other	—	—	1	1	2
Adjusted EBITDA (1)(2)	$ 83	$ 61	$ 575	$ (91)	$ 628

(1) EBITDA and Adjusted EBITDA are non-GAAP financial measures. Please refer to Item 2.02 of our Form 8-K filed on November 1, 2016, for definitions, utility and uses of such non-GAAP financial measures. A reconciliation of EBITDA to Operating income (loss) is presented below. Management does not allocate interest expense and income taxes on a segment level and therefore uses Operating income (loss) as the most directly comparable GAAP measure.

(2) Not adjusted for these items which are excluded in 2016: (i) non-cash compensation expense of $20 million, and (ii) Wood River's energy margin and O&M costs of $9 million.

	Nine Months Ended September 30, 2015				
	Coal	**IPH**	**Gas**	**Other**	**Total**
Operating income (loss)	$ (34)	$ 39	$ 290	$ (218)	$ 77
Depreciation and amortization expense	78	27	306	3	414
Losses from unconsolidated investment	—	—	(1)	—	(1)
Other income and expense, net	—	—	—	45	45
EBITDA	$ 44	$ 66	$ 595	$ (170)	$ 535

REG G RECONCILIATION – CURRENT YEAR-TO-DATE ADJUSTED EBITDA

DYNEGY INC.
REPORTED SEGMENTED RESULTS OF OPERATIONS
NINE MONTHS ENDED SEPTEMBER 30, 2016
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our Adjusted EBITDA by segment for the nine months ended September 30, 2016:

	Nine Months Ended September 30, 2016				
	Coal	IPH	Gas	Other	Total
Net loss attributable to Dynegy Inc.					$ (1,060)
Plus / (Less):					
Loss attributable to noncontrolling interest					(2)
Income tax expense					6
Interest expense					449
Depreciation and amortization expense					529
EBITDA (1)	$ (632)	$ (52)	$ 716	$ (110)	$ (78)
Plus / (Less):					
Adjustments to reflect Adjusted EBITDA from unconsolidated investment and exclude noncontrolling interest	—	—	—	—	—
Acquisition, integration and restructuring costs	—	(8)	—	21	13
Mark-to-market adjustments, including warrants	23	(3)	(61)	(5)	(46)
Impairments	700	148	9	—	857
Wood River energy margin and O&M	23	—	—	—	23
Non-cash compensation expense	—	—	2	16	18
Other	1	(3)	1	2	1
Adjusted EBITDA (1)	$ 115	$ 82	$ 667	$ (76)	$ 788

(1) EBITDA and Adjusted EBITDA are non-GAAP financial measures. Please refer to Item 2.02 of our Form 8-K filed on November 1, 2016, for definitions, utility and uses of such non-GAAP financial measures. A reconciliation of EBITDA to Operating income (loss) is presented below. Management does not allocate interest expense and income taxes on a segment level and therefore uses Operating income (loss) as the most directly comparable GAAP measure.

	Nine Months Ended September 30, 2016				
	Coal	IPH	Gas	Other	Total
Operating income (loss)	$ (728)	$ (87)	$ 279	$ (138)	$ (674)
Depreciation and amortization expense	87	20	418	4	529
Earnings from unconsolidated investment	—	—	7	—	7
Other income and expense, net	9	15	12	24	60
EBITDA	$ (632)	$ (52)	$ 716	$ (110)	$ (78)

REG G RECONCILIATION –DYNEGY 2016 ADJUSTED EBITDA AND FREE CASH FLOW GUIDANCE

DYNEGY INC.
2016 ADJUSTED EBITDA AND FREE CASH FLOW GUIDANCE
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our 2016 Adjusted EBITDA guidance, updated based on October 12, 2016 forward curves, as presented on November 1, 2016:

	Dynegy Consolidated	
	Low	High
Net loss attributable to Dynegy Inc. (1)	$ (1,258)	$ (1,188)
Plus / (Less):		
Loss attributable to noncontrolling interest (2)	(2)	(2)
Income tax expense (2)	6	6
Interest expense	625	630
Depreciation and amortization expense	685	705
EBITDA (3)	**56**	**151**
Plus / (Less):		
Acquisition, integration and restructuring costs	45	50
Impairments (2)	857	857
Other (4)	42	42
Adjusted EBITDA (3)	**$ 1,000**	**$ 1,100**

(1) For purposes of our 2016 guidance, fair value adjustments related to derivatives and our common stock warrants are assumed to be zero.

(2) Represents actual amounts for the nine months ended September 30, 2016.

(3) EBITDA and Adjusted EBITDA are non-GAAP measures. Please refer to Item 2.02 of our Form 8-K filed on November 1, 2016, for definitions, utility and uses of such non-GAAP financial measures.

(4) Represents actual amounts for nine months ended September 30, 2016. Other consists primarily of adjustments to reflect Adjusted EBITDA from unconsolidated investment and exclude noncontrolling interest, non-cash compensation expense, and Wood River's energy margin and operating and maintenance costs.

The following table provides summary financial data regarding our 2016 Free Cash Flow guidance:

	Dynegy Consolidated	
	Low	High
Adjusted EBITDA (1)	$ 1,000	$ 1,100
Cash interest payments (2)	(515)	(515)
Acquisition, integration and restructuring costs	(45)	(50)
Other cash items	10	10
Cash Flow from Operations	**450**	**545**
Maintenance capital expenditures	(275)	(275)
Environmental capital expenditures	(20)	(20)
Acquisition, integration and restructuring costs	45	50
Free Cash Flow (1)	**$ 200**	**$ 300**

(1) Adjusted EBITDA and Free Cash Flow are non-GAAP measures. Please refer to Item 2.02 of our Form 8-K filed on November 1, 2016, for definitions, utility and uses of such non-GAAP financial measures.

(2) Excludes payments to an escrow account of (i) $50 million of pre-funded interest and (ii) $20 million of prefunded, original issue discount which are contingent upon the closing of the ENGIE acquisition.

REG G RECONCILIATION – IPH 2016 ADJUSTED EBITDA GUIDANCE

ILLINOIS POWER HOLDINGS (IPH)
2016 ADJUSTED EBITDA GUIDANCE
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our IPH 2016 Adjusted EBITDA guidance, based on October 12, 2016 forward curves, as presented on November 1, 2016:

Operating income	$	78
Depreciation and amortization expense		30
EBITDA (1)		108
Plus / (Less):		
Acquisition and integration costs		(8)
Adjusted EBITDA (1)	$	100

(1) Adjusted EBITDA is a non-GAAP measure. Please refer to Item 2.02 of our Form 8-K filed on November 1, 2016, for definitions, utility and uses of such non-GAAP financial measures. Management does not allocate interest expense and income taxes on a segment level and therefore uses Operating Income (Loss) as the most directly comparable GAAP measure.

REG G RECONCILIATION –DYNEGY 2017 ADJUSTED EBITDA AND FREE CASH FLOW GUIDANCE

DYNEGY INC.
2017 ADJUSTED EBITDA AND FREE CASH FLOW GUIDANCE
(UNAUDITED) (IN MILLIONS)

The 2017 guidance was prepared using reasonable efforts and based on currently available information assuming the following: (a) the Delta transaction will close on December 31, 2016, (b) all of the purchase price is allocated to property, plant and equipment, (c) property, plant and equipment is depreciated over an average useful life of 20 years, and (d) Genco restructuring will be completed in the first quarter of 2017.

The following table provides summary financial data regarding our 2017 Adjusted EBITDA guidance, updated based on October 12, 2016 forward curves, as presented on November 1, 2016:

	Dynegy Consolidated	
	Low	High
Net loss attributable to Dynegy Inc. (1)	$ (290)	$ (120)
Plus / (Less):		
Interest expense	680	685
Depreciation and amortization expense	795	815
EBITDA (2)	**1,185**	**1,380**
Plus / (Less):		
Acquisition, integration and restructuring costs	15	20
Adjusted EBITDA (2)	**$ 1,200**	**$ 1,400**

(1) For purposes of our 2017 guidance, fair value adjustments related to derivatives and our common stock warrants are assumed to be zero.

(2) EBITDA and Adjusted EBITDA are non-GAAP measures. Please refer to Item 2.02 of our Form 8-K filed on November 1, 2016, for definitions, utility and uses of such non-GAAP financial measures.

The following table provides summary financial data regarding our 2017 Free Cash Flow guidance:

	Dynegy Consolidated	
	Low	High
Adjusted EBITDA (1)	$ 1,200	$ 1,400
Cash interest payments	(625)	(625)
Acquisition, integration and restructuring costs	(15)	(20)
Other cash items	(35)	(35)
Cash Flow from Operations	**525**	**720**
Maintenance capital expenditures	(370)	(370)
Environmental capital expenditures	(20)	(20)
Acquisition, integration and restructuring costs	15	20
Free Cash Flow (1)	**$ 150**	**$ 350**

(1) Adjusted EBITDA and Free Cash Flow are non-GAAP measures. Please refer to Item 2.02 of our Form 8-K filed on November 1, 2016, for definitions, utility and uses of such non-GAAP financial measures.