NRG Energy Inc.

Second Quarter 2017 Earnings Presentation

August 3, 2017

Safe Harbor

Forward-Looking Statements

In addition to historical information, the information presented in this communication includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Exchange Act. These statements involve estimates, expectations, projections, goals, assumptions, known and unknown risks and uncertainties and can typically be identified by terminology such as "may," "should," "could," "objective," "projection," "forecast," "goal," "guidance," "outlook," "expect," "intend," "seek," "plan," "think," "anticipate," "estimate," "predict," "target," "potential" or "continue" or the negative of these terms or other comparable terminology. Such forward-looking statements include, but are not limited to, statements about the Company's future revenues, income, indebtedness, capital structure, plans, expectations, objectives, projected financial performance and/or business results and other future events, and views of economic and market conditions.

Although NRG believes that its expectations are reasonable, it can give no assurance that these expectations will prove to be correct, and actual results may vary materially. Factors that could cause actual results to differ materially from those contemplated herein include, among others, general economic conditions, hazards customary in the power industry, weather conditions, including wind and solar performance, competition in wholesale power markets, the volatility of energy and fuel prices, failure of customers to perform under contracts, changes in the wholesale power markets, changes in government regulations, the condition of capital markets generally, our ability to access capital markets, unanticipated outages at our generation facilities, adverse results in current and future litigation, failure to identify, execute or successfully implement acquisitions, repowerings or asset sales, our ability to implement value enhancing improvements to plant operations and companywide processes, our ability to implement and execute on our publicly announced transformation plan, including any cost savings, margin enhancement, asset sale, and net debt targets, our ability to proceed with projects under development or the inability to complete the construction of such projects on schedule or within budget, risks related to project siting, financing, construction, permitting, government approvals and the negotiation of project development agreements, our ability to progress development pipeline projects, the timing or completion of the GenOn restructuring, the inability to maintain or create successful partnering relationships, our ability to operate our businesses efficiently, our ability to retain retail customers, our ability to realize value through our commercial operations strategy and the creation of NRG Yield, the ability to successfully integrate businesses of acquired companies, our ability to realize anticipated benefits of transactions (including expected cost savings and other synergies) or the risk that anticipated benefits may take longer to realize than expected, our ability to close the Drop Down transactions with NRG Yield, and our ability to execute our Capital Allocation Plan. Debt and share repurchases may be made from time to time subject to market conditions and other factors, including as permitted by United States securities laws. Furthermore, any common stock dividend is subject to available capital and market conditions.

NRG undertakes no obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by law. The adjusted EBITDA and free cash flow guidance are estimates as of August 3, 2017. These estimates are based on assumptions the company believed to be reasonable as of that date. NRG disclaims any current intention to update such guidance, except as required by law. The foregoing review of factors that could cause NRG's actual results to differ materially from those contemplated in the forward-looking statements included in this presentation should be considered in connection with information regarding risks and uncertainties that may affect NRG's future results included in NRG's filings with the Securities and Exchange Commission at www.sec.gov.

Agenda

Business Review
Mauricio Gutierrez, President and CEO

Financial Update
Kirk Andrews, EVP and CFO

Closing Remarks
Mauricio Gutierrez, President and CEO

Q&A

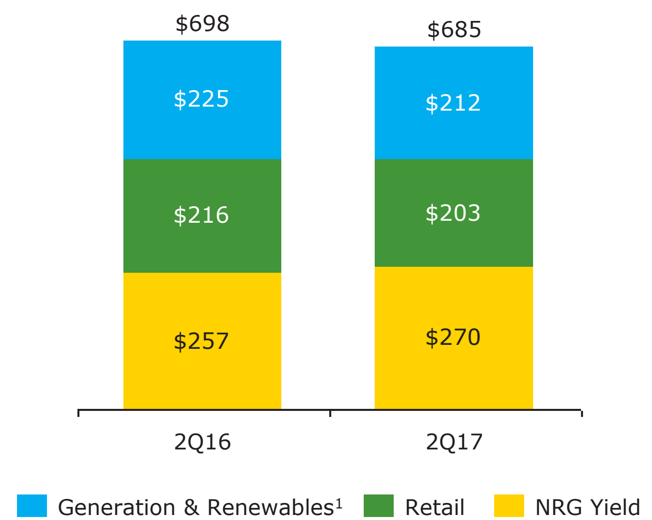
Q2 2017 Review & Highlights

Q2 Business Updates

- ☑ **Strong Q2 Results; Reaffirming 2017 Guidance**
- ☑ **Executing on Capital Recycling through NYLD:**
  - Closed drop down of remaining 25% interest in NRG Wind TE Holdco
  - Offered to drop down a 38 MW portfolio currently outside the ROFO pipeline
  - Offered to form a new $50 MM distributed solar partnership with NRG Yield
- ☑ **Focusing on Transformation Plan Targets:**
  - $855 MM recurring annual FCFbG-accretive cost and margin improvements and $210 MM permanent SG&A reductions from asset sales and divestments
  - $2.5 - $4.0 Bn asset sale net cash proceeds
  - Up to $6.3 Bn in excess cash after achieving 3.0x net debt / Adj. EBITDA through 2020
- ☑ **GenOn Restructuring Underway:**
  - Bankruptcy filed 6/14/17; expect 4-6 month expedited bankruptcy process
  - GenOn fully deconsolidated from NRG financials

Year-over-Year Quarterly Results

Adjusted EBITDA ($MM)



Reaffirming 2017 Guidance Ranges:

$2,565 - $2,765 Adjusted EBITDA
$1,290 - $1,490 Free Cash Flow before Growth

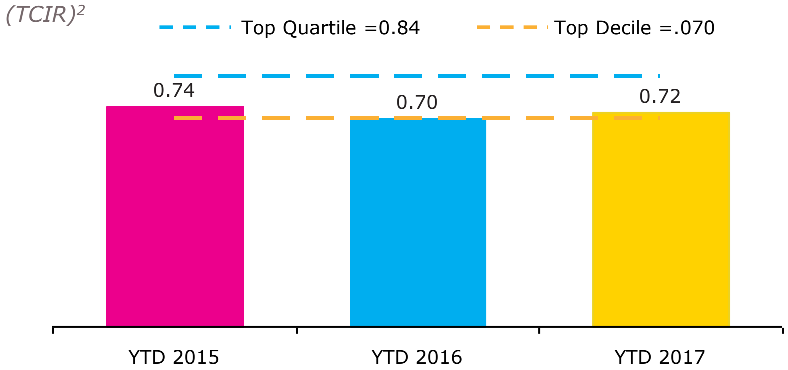
NRG Delivers Strong Second Quarter Results;
Reaffirming 2017 Financial Guidance

[1] Includes Corporate Segment

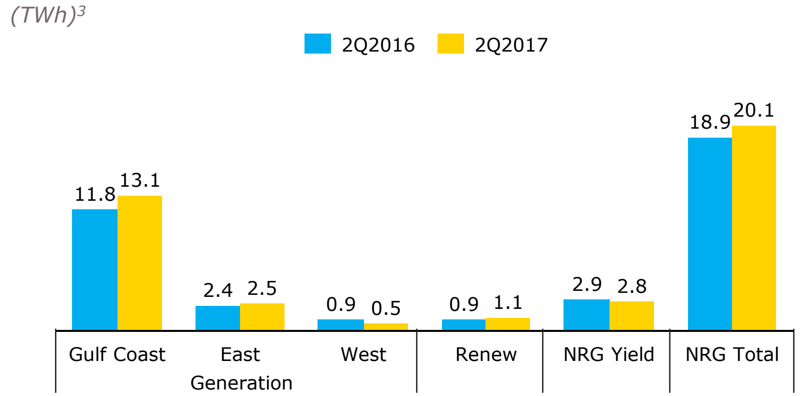
Operational Metrics

All metrics exclude GenOn

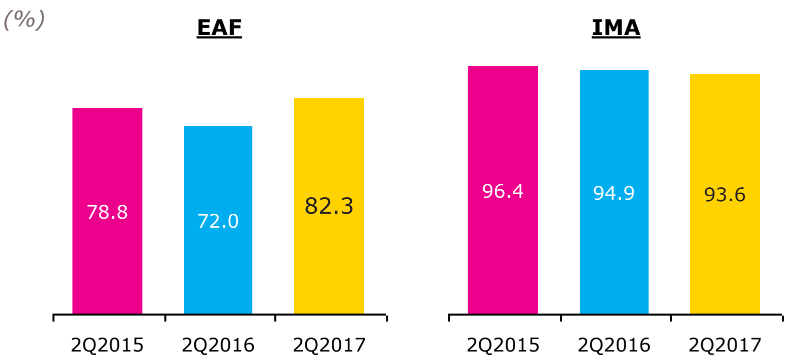
Safety[1]



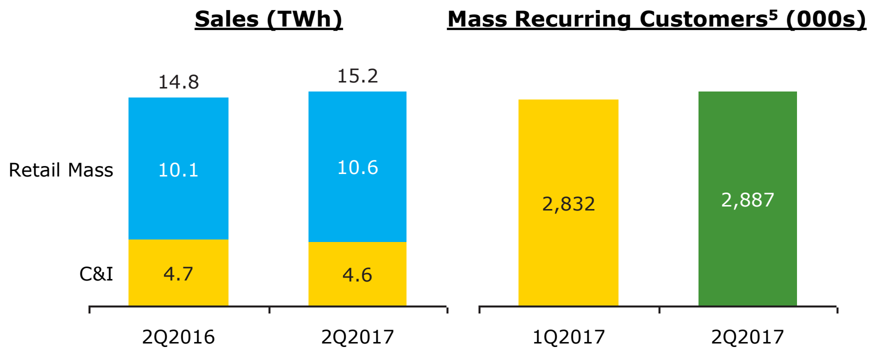
Production



Baseload Equivalent Availability Factor and In-the-Money-Availability



Retail Operations[4]



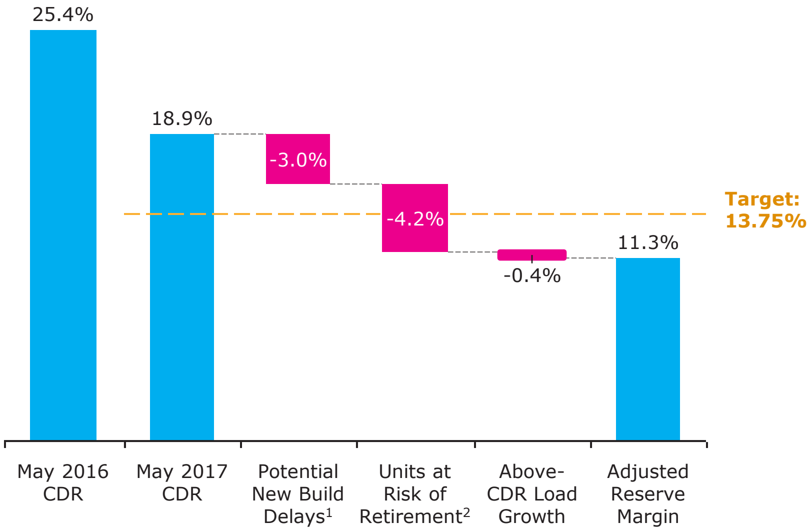
Higher Total Generation and Retail Sales Coupled with Strong Generation Availability

[1] Excludes Goal Zero, NRG Home Services and NRG Home Solar; top decile and top quartile based on Edison Electric Institute 2015 Total Company Survey results; [2] TCIR = Total Case Incident Rate; [3] All NRG-owned domestic generation, including NRG Yield Thermal MWht; excludes line losses, station service, and other items. Generation data presented above consistent with US GAAP accounting. Previous reports were pro-forma for acquisitions in prior periods; [4] Second quarter sales volumes exclude load associated with customer self-supply; [5] Excludes C&I and NRG Home Solar customers; mass recurring customer count includes customers that subscribe to one or more recurring services, such as electricity and natural gas service

Market Update

ERCOT: Reserve Margins Under Continued Pressure

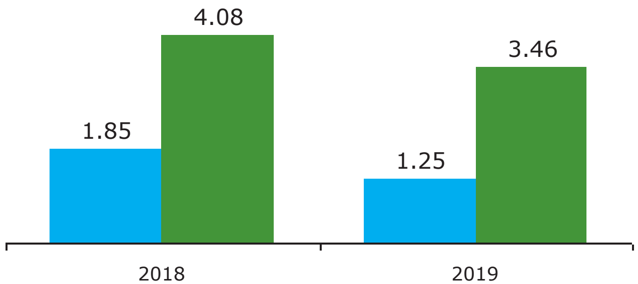
CDR 2018 Reserve Margin



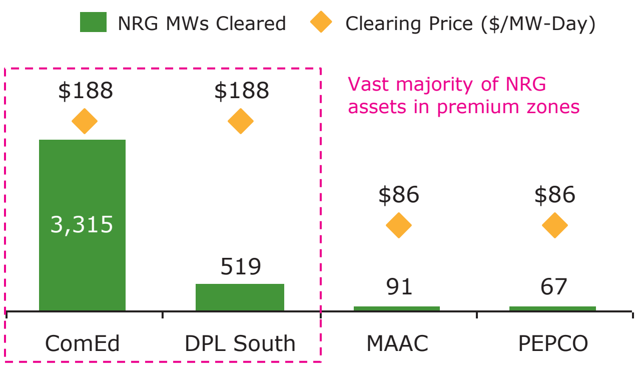
- Load growth (+2.3%[3]) outpaces national average
- New build delays / cancellations in 2018 conventional capacity ~1.2 GW; more expected in 2019, 2020
- 3 GW – 8 GW of units at risk of retirement over next several years

ERCOT and PJM: NRG Assets Well-Positioned Within Key Markets

ERCOT: Forward Houston over North On-Peak Basis[4] ($/MWh)



PJM: 20/21 Base Residual Auction



ERCOT Market Continues to Tighten and Demonstrate Strong Fundamentals; NRG Assets Well-Positioned in ERCOT and PJM

[1] Includes Bacliff (324 MW, project terminated), Halyard Henderson (450 MW, project delayed), and Halyard Wharton (419 MW, project delayed) and 50% of planned renewables, in line with 2016 actual results; [2] Represents 3,000 MW of potential retirements; [3] Represents 12-month average of year over year weather normalized demand growth; [4] Represents Houston to North on peak basis

Financial Update

Financial Summary

($ millions)	June 30, 2017 Three Months Ended	June 30, 2017 Six Months Ended	2017 Reaffirmed Guidance[1]
Generation & Renewables[2,3]	$212	$281	$945 – $1,065
Retail	203	336	700 – 780
NRG Yield[3]	270	454	920
Adjusted EBITDA	**$685**	**$1,071**	**$2,565–$2,765**
Consolidated Free Cash Flow before Growth (FCFbG)	**$240**	**$208**	**$1,290–$1,490**

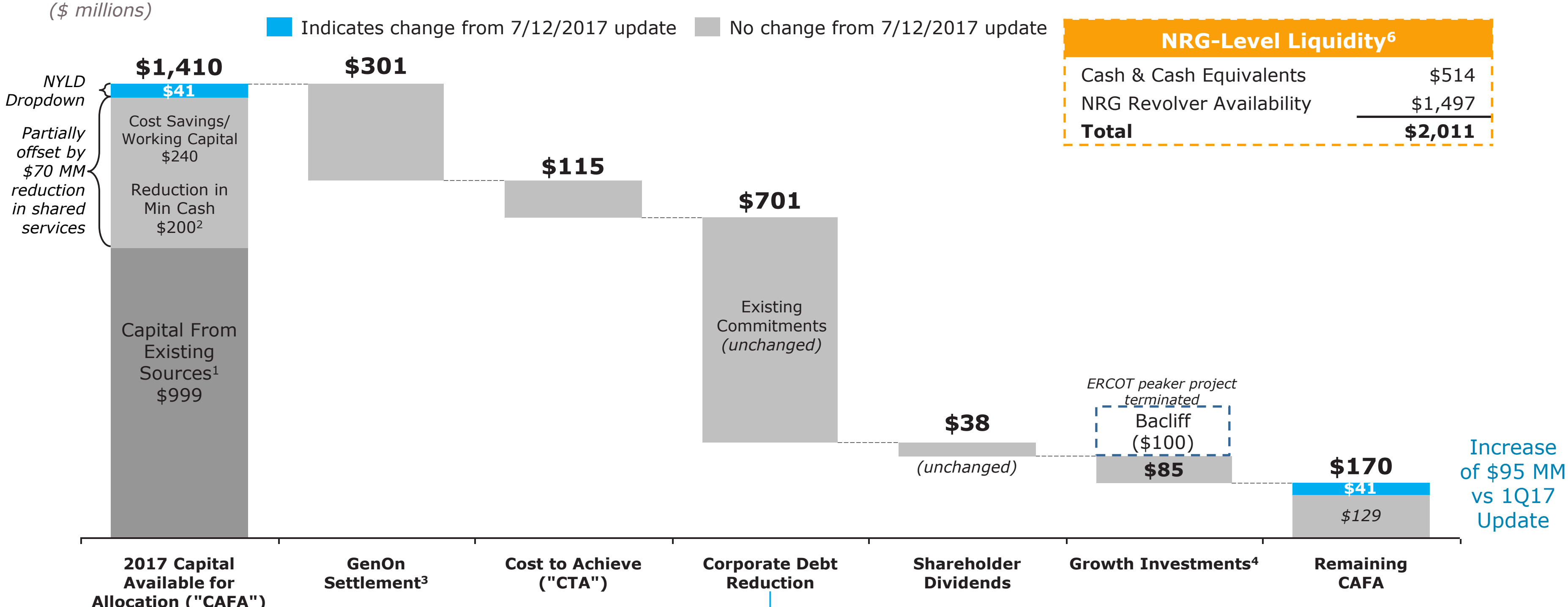
- GenOn now deconsolidated from financial results and guidance
- 2Q17 Adjusted EBITDA within 2% of prior year's result
- Closed on sale of remaining 25% in the NRG Wind TE Holdco portfolio to NRG Yield for $41.5 MM[4,5] increasing capital available for allocation
- Offered NRG Yield a 38 MW portfolio of distributed and small utility-scale solar assets
- Offered NRG Yield a new $50 MM distributed solar partnership
- ~$500 MM in net proceeds from non-recourse project financings including $350 MM for Carlsbad
- Completely repaid $125 MM corporate revolver using excess cash on hand

[1] Guidance reflects deconsolidation of GenOn, $65 MM of cost reductions and $175 MM of working capital improvements as part of the Transformation Plan announced on July 12, 2017; [2] Includes Corporate Segment; [3] In accordance with GAAP, restated to reflect impact of Utah Solar and 31% of NRG's interest in Agua Caliente drop down to NRG Yield; [4] Excludes adjustment for working capital; [5] Does not reflect potential additional payment based on actual energy prices in merchant periods beginning 2027

2017 NRG-Level Capital Allocation

($ millions)

NRG-Level Liquidity[6]	
Cash & Cash Equivalents	$514
NRG Revolver Availability	$1,497
Total	**$2,011**



Retirement of 2018 Notes	$398
Reserve for Additional Debt Reduction	$200
Term Loan Amortization	$19
Midwest Gen Debt Amortization[5]	$80
Term Loan Refi Fees	$4

$200 MM Decrease in Cash Reserve Target and NYLD Drop Down Help Fund GenOn Settlement and Increase 2017 Surplus

[1] Refer to slide 13 of NRG 4Q16 earnings presentation. Capital from Existing Sources includes: 2016 YE cash & cash equivalents at NRG level of $570 MM less prior cash target of $700 MM (net of $71 MM in NRG Level cash collateral postings) plus midpoint of NRG-level FCFbG guidance of $800 MM plus $128 MM of Agua Caliente project-level net financing proceeds closed on 2/17/2017 and $130 MM of gross proceeds from drop down of Utah solar assets and 16% interest in Agua Caliente to NRG Yield closed on 3/27/2017, prior to working capital adjustments; [2] Company intends to maintain $500 MM of cash for collateral posting and other liquidity needs (compared to $700 MM at the beginning of the year); [3] $261.3 MM settlement plus $13 MM in pension funding plus $27 MM credit related to GenOn's 2022 Senior Notes issuance; [4] Net of financing; [5] Represents 2017 capacity revenue sold of $80 MM against $253 MM monetized in 2016; [6] Includes $125 MM cash held at MWG which can be distributed to NRG Corporate with no restrictions; revolver availability represents $2.5 Bn revolving credit facility, less $1.0 Bn of letters of credit issued

NRG's Capital Structure & Corporate Credit Metrics

($ millions)

Debt and Cash Balances as of 6/30/2017

NRG Energy, Inc.[1]

	Consolidated	Recourse
Total Debt:	$17,131	$7,791[2]
Total Cash:	$752	$514

Non-Recourse Debt
(Excluded Project Sub)

NRG Yield	ROFO/Renewables	Conventional[9]
Total Debt: $5,983	Total Debt: $2,811	Total Debt: $546

~ $9.3 Bn

	2017E Post-Capital Allocation
Recourse Debt *(06/30/2017)*[2]	**$7,791**
2018 Maturity Reserve	(398)
2017 Term Loan Amortization	(10)
Additional Debt Reduction	(200)
Pro Forma Corporate Debt	**~$7,200**
Mid-Point Adj. EBITDA[3]	$2,665
Less Adjusted EBITDA:	
NRG Yield	(920)
ROFO / Renewables / Conventional[4]	(345)
Add:	
NRG Yield Distributions to NRG[5]	90
ROFO / Other Dividends to NRG[6]	110
Other Adjustments[7]	150
Total Recourse EBITDA	**$1,750**
Corporate Debt/Corporate EBITDA	**4.10x**
Cash & Cash Equivalents @ NRG-Level[8]	$670
Corporate Net Debt/Corporate EBITDA	**3.72x**

Maintaining Balance Sheet Metrics In-Line With Targets

[1] Reflects deconsolidation of GenOn; [2] Includes NRG Energy Inc. term loan facility, senior notes, revolver, capital leases and tax exempt bonds; [3] Includes $120 MM shared service payment from GenOn; [4] Previously referred to as "ROFO/Other", includes Agua Caliente, Ivanpah, Yield eligible assets, Capistrano, other renewable assets, and Midwest Generation (~$120MM); [5] Estimate based on NRG Yield dividends equivalent to $1.15/share annualized by Q4 and excludes impact of drop-down proceeds; [6] Includes MWG distributions of ~$60 MM; [7] Reflects non-cash expenses (i.e. nuclear amortization, equity compensation amortization, and bad debt expense) that are included in Adjusted EBITDA; [8] NRG-Level CAFA 2017 YE CAFA of $170 MM (see prior slide) plus $500 MM minimum cash; [9] Previously in "ROFO/Other"; see appendix slide 40 for details

Closing Remarks

2017 Priorities

- ☑ **Reaffirming Full Year Guidance Ranges**

- ❑ **Focus on Execution of the NRG Transformation Plan 2017 Objectives** (Cost and Margin Enhancements, Portfolio Optimization, Capital Structure and Allocation)

- ❑ **Finalize Comprehensive Resolution for GenOn**
  - ☑ Filed Chapter 11 on 6/14/17
  - ❑ Final resolution (expected by Year End 2017)

- ❑ **Identify and Execute on Growth Opportunities with High Returns and Quick Capital Replenishment**
  - ☑ Closed drop down in 1Q17 of 31% of NRG's interest Agua Caliente and Utah Solar Assets to NRG Yield
  - ☑ Closed drop down of remaining 25% interest in NRG Wind TE Holdco to NRG Yield
  - ❑ Offered to form a new $50 MM distributed solar partnership with NRG Yield
  - ❑ Offered to drop down a 38 MW portfolio to NRG Yield, currently outside the ROFO pipeline

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Q&A

Appendix: Transformation Plan Highlights

Please see NRG Investor Relations website for full 7/12/2017 Transformation Plan presentation.
All slide references in this section correspond to the NRG Transformation Plan presentation.

NRG Transformation Plan:
Process Background

The Business Review Committee ("BRC"), NRG management, and independent consultants/advisors conducted a 4-month, comprehensive evaluation across all NRG businesses, assets, and functions

The BRC review had three key focus areas: Operational and cost excellence initiatives, asset deconsolidations, dispositions and portfolio optimization, and capital structure and allocation

The BRC unanimously recommended a 3-part, 3-year transformation plan that was fully supported and approved by the NRG Board of Directors and NRG Management

The NRG transformation plan is front-loaded with realistic and achievable targets that can be implemented immediately

Transformation Plan Summary

1 Achieve Cost Leadership and Enhance Earnings

- **$1,065 MM** in recurring cost and margin improvements: ~**70%** achieved by YE 2018 and over **90%** by YE 2019
  - Implement **$855 MM** recurring, annual free cash flow before growth (FCFbG) accretive cost reduction and margin enhancement program with 75+ levers identified to enhance value:
    - **$590 MM** cost savings; **$215MM** margin enhancement program; **$50 MM** maintenance capex reduction
  - Realize **$210 MM** permanent SG&A reduction associated with asset sales and divestments in 2018
- Achieve **$370 MM** working capital improvements and full plan's **$290 MM** one-time costs to achieve

2 Optimize Portfolio and Increase Focus on Integrated Platform

- Target net cash proceeds of **$2.5 - $4.0 Bn** from asset sales with sales announced by YE 2017, associated costs and debt reductions realized in 2018, and proceeds to be tax efficient given sizable NOL
- Divest **~21 GW** of conventional generation and businesses, including GenOn
- To **monetize 50% - 100%** of NRG's interest in NRG Yield and Renewables to deconsolidate and simplify NRG structure while maintaining ability to provide comprehensive energy solutions

3 Focus on Disciplined Capital Allocation, priorities:

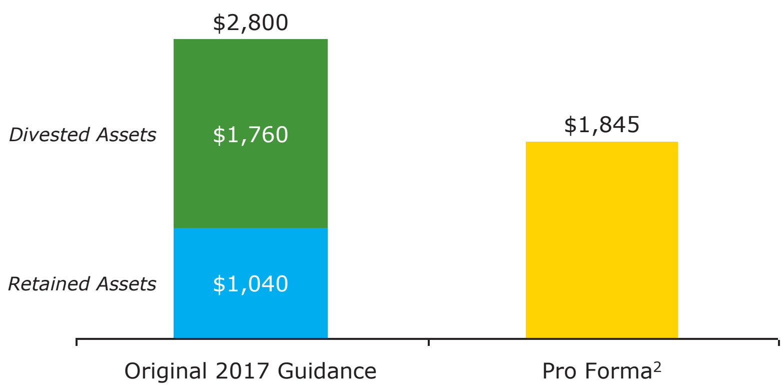
- First: Achieve and maintain **top decile safety** and operational excellence
- Second: Reduce net debt/adjusted EBITDA to **3.0x** by YE 2018
- Third: Selectively invest in compelling projects with less than **5 year payback** period and stringent unlevered pre-tax return of at least **12% - 15%**
- Fourth: Allocate to **shareholder return programs** once capital structure objectives have been met and high capital return investments have been funded

4 Strong Governance Focused on Transformation Plan Achievement

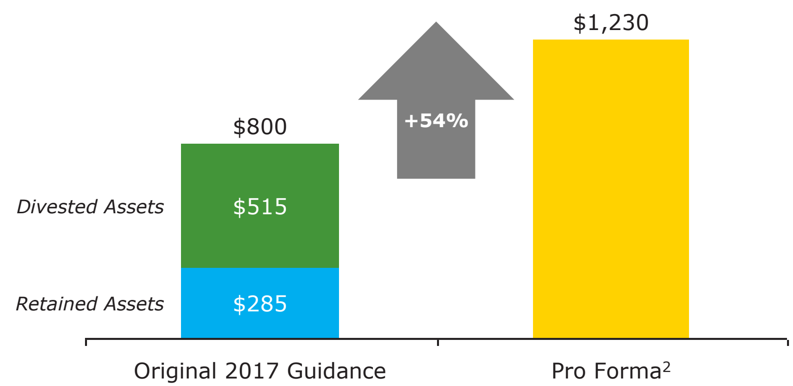
- Oversight by full Board of Directors with monthly updates to the Board's Finance and Risk Management Committee and quarterly scorecard to investors
- Newly created dedicated implementation team
- Existing management compensation aligned to Transformation Plan execution and success

NRG Transformation Plan
Pro Forma Impacts

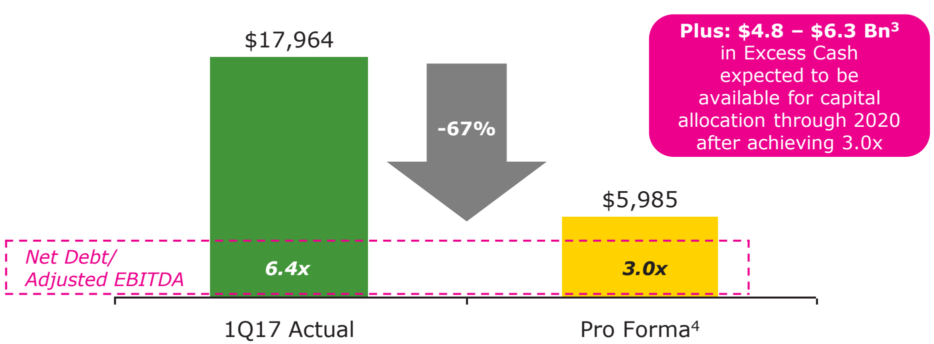
Adjusted EBITDA[1] ($ MM)



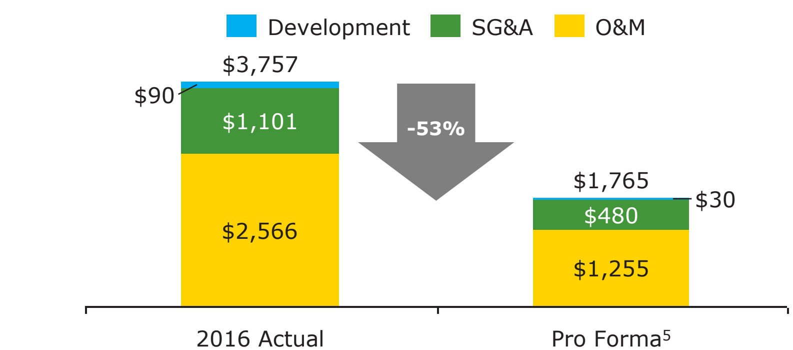
NRG-Level FCFbG[1] ($ MM)



Consolidated Net Debt ($ MM)



Total Operating Costs ($ MM)



Removing ~$12 Bn from Consolidated Net Debt Structure While Increasing Free Cash Flow Before Growth by Over 50%

Note: All references in this section correspond to the NRG Transformation Plan presentation
[1] Based on 2017 midpoint guidance; [2] Guidance as of 1Q 2017, ex-GenOn, post asset sales and divestitures and full impact of cost and margin enhancement program; [3] See slide 16 for details (total cash less $500 MM cash for collateral posting and other liquidity needs); [4] See slide 17 ($6,485 MM of total Pro Forma debt less $500 MM cash for collateral posting and other liquidity needs); [5] See slide 15, excludes recurring SG&A and O&M costs to support margin enhancements

NRG Transformation Plan
Pro Forma Financial Road Map

($ millions)	Guidance as of 1Q 2017 (2016 actuals where noted)	GenOn Divestment	Asset Sales[3]	Impact of Cost and Margin Enhancement	Interest Savings / Debt Reduction	Pro Forma Full Transformation Plan
	(midpoint)	(midpoint)	(midpoint)	(midpoint)	(midpoint)	(midpoint)
Adj. EBITDA	2,800	(320)[2]	(1,440)	805	--	1,845
Consolidated FCFbG	900	130	(745)	855	90[5]	1,230
NRG-Level FCFbG	800	(190)	(325)	855	90[5]	1,230
Total Consolidated Debt	19,477[1]	(2,624)	(8,713)	--	(1,655)[6]	6,485
Cost Detail:						
O&M and Other (2016A)	*2,566*	(620)	(521)	(170)[4]	--	1,255[4]
SG&A (2016A)	*1,101*	(10)	(201)	(410)[4]	--	480[4]
Development (2016A)	*90*	--	(50)	(10)	--	30
Maintenance Capex	295	(70)	(50)	(50)	--	125
Interest Expense	1,065	(240)	(380)	--	(90)[5]	355

Note: All references in this section correspond to the NRG Transformation Plan presentation
[1] As of 3/31/2017; [2] Midpoint of 2017 EBITDA guidance of $130 MM plus shared service of ~$190 MM (eliminates on NRG consolidation); [3] Assumes sale of ~6 GW in conventional assets and 100% of NRG's interest in NRG Yield and Renewables; [4] Excludes any increase in recurring SG&A and O&M to support targeted margin enhancements; [5] Assumes 7.0% interest rate on both $613 MM of planned corporate debt reduction in 2017 capital allocation and required corporate deleveraging of ~$640 MM to achieve 3.0x consolidated net debt/EBITDA target; [6] ~$1,655 MM = $125 MM repayment of NRG revolver in connection with GenOn settlement, $613 MM of 2017 capital allocated to deleveraging, $60 MM in term loan amortization through 2020 and $640 MM in additional deleveraging following asset divestitures to achieve 3.0x consolidated net debt/adj. EBITDA target, plus $220 MM of MWG capacity amortization

NRG Transformation Plan
Corporate Credit Metric Update

($ millions)	**Guidance as of 1Q 2017**	GenOn Divestment	Asset Sales	Impact of Cost and Margin Enhancement	**Pro Forma Full Transformation Plan**
Corporate Debt *(3/31/2017)*	**$7,923**	*($125)*[1]			**$7,798**
2018 Maturity Reserve	(398)				(398)
2017 Term Loan Amortization	(15)				(75)
Additional Debt Reduction	(200)		*($640)*[2]		(840)
Pro Forma Corporate Debt	**$7,310**	*($125)*	*($640)*		**$6,485**
Corporate Cash & Cash Equivalents	645[3]				500
Pro Forma Corporate Net Debt	**$6,665**				**$5,985**
Midpoint Adj. EBITDA	**$2,800**	***($320)***	***($1,440)***	***$805***	**$1,845**[4]
Less Adjusted EBITDA:					
GenOn[5]	(130)	*$130*			--
NRG Yield	(920)		*$920*		--
ROFO / Other	(345)		*$345*		--
Add:					
NRG Yield Distributions to NRG[6]	90		*($90)*		--
ROFO / Other Dividends to NRG	110		*($110)*		--
Other Adjustments[7]	150				150
Total Corporate EBITDA	**$1,755**				**$1,995**
Corporate Debt/Corporate EBITDA	**4.17x**				**3.25x**
Corporate Net Debt/Corporate EBITDA	**3.80x**				**3.0x**
Consolidated Net Debt	**$17,964**				**$5,985**[8]
Consolidated Net Debt/Total EBITDA	**6.4x**				**3.0x**

Plus: Excess Cash up to $6.3 Bn[9]

Achieving 3.0x Net Debt/Adj. EBITDA with Significant Cash Surplus of up to $20/share

Note: All references in this section correspond to the NRG Transformation Plan presentation
[1] Reflects repayment of drawn portion of GenOn intercompany revolver and corresponding repayment of NRG revolver; [2] See slide 16; represents remaining debt reduction to realize 3.0x net debt/EBITDA; [3] NRG-Level cash of $570 MM as of 12/31/16 plus remaining CAFA of $75 MM (prior guidance – see slide 10 of 1Q earnings presentation); [4] Midpoint of 2017 Post Asset Sales and Cost and Margin Enhancement (see slide 15); [5] Net of shared service payment by GenOn to NRG; [6] Excludes impact of drop-down proceeds; [7] For the purpose of credit agreement, adjustments reflect non-cash expenses (i.e. nuclear amortization, equity compensation, and bad debt expense) that are included in reported Adjusted EBITDA; [8] $6,485 MM of total Pro Forma debt less $500 MM cash for collateral posting and other liquidity needs; [9] See slide 16

2017 Financial Guidance Walk
Impact of GenOn and Plan Improvements

($ millions)	**Previous Guidance**	GenOn Deconsolidation	Shared Services	Transformation Plan[3]	**Updated Guidance**
Generation & Renewables[1]	$1,080 – $1,200	(320)	120	65	$945– $1,065
Retail	700 – 780				700 – 780
NRG Yield	920[2]				920
Adjusted EBITDA	**$2,700–$2,900**	**(320)** A	**120** C	**65**	**$2,565–$2,765**
Consolidated FCFbG	**$800–$1,000**	**130** B	**120**	**240** E	**$1,290–$1,490**
NRG-Level FCFbG	**$700–$900**	**-**	**(70)** D	**240**	**$870–$1,070**

A GenOn to be deconsolidated from results for full year 2017, eliminating GenOn contribution to Consolidated Adjusted EBITDA of $320 MM (midpoint)

B Eliminate GenOn NEGATIVE contribution to 2017 Consolidated FCFbG of ($130 MM)

C Due to deconsolidation, NRG recognizes GenOn shared service payments as follows:

- ~$90 MM in shared service revenues to NRG YTD (@$193 MM annualized rate)
- ~$30 MM in shared service revenues for balance of year (4 months at $84 MM annualized rate plus 2 months at no charge – assuming emergence from bankruptcy within 4 months)

Revised shared service revenues ~$120 MM

D Deduct ~$70 MM for reduction in Shared Services (Previous: $193 MM, Revised: ~$120 MM)

E $65 MM of cost savings expected to be realized in 2017 (Adj. EBITDA) plus $175 MM of working capital improvements

Original Guidance Maintained
Adjusted for GenOn Settlement Plus 2017 Impact of Transformation Plan

Note: All references in this section correspond to the NRG Transformation Plan presentation
[1] Includes Corporate Segment; [2] Guidance as of the NRG Yield 1Q 2017 earnings call; [3] Excludes cost to achieve (treated as capital allocation)

Transformation Plan Score Card

Progress, as of 7/12/17

($ millions)	2017 Progress: 2017 Target	2017 Progress: % achieved	2018	2019	Run Rate
Accretive & Recurring:					
Cost Savings	65	0%			
Margin Enhancement	0	0%			
Total EBITDA - Accretion	**$65**	**0%**			
Maintenance Capex	0	0%			
Total Recurring FCFbG Accretion	**$65**	**0%**			
Non-Recurring:					
Working Capital Improvement	175	0%			
Cost to Achieve Total Transformation Plan	(115)	0%			
Total Non-Recurring	**$60**	**0%**			
Annual Cash Accretion	**$125**	**0%**			
Cumulative Cash Accretion *(Incremental Capital Available for Allocation)*	**$125**	**0%**			

Stated Target, 7/12/17

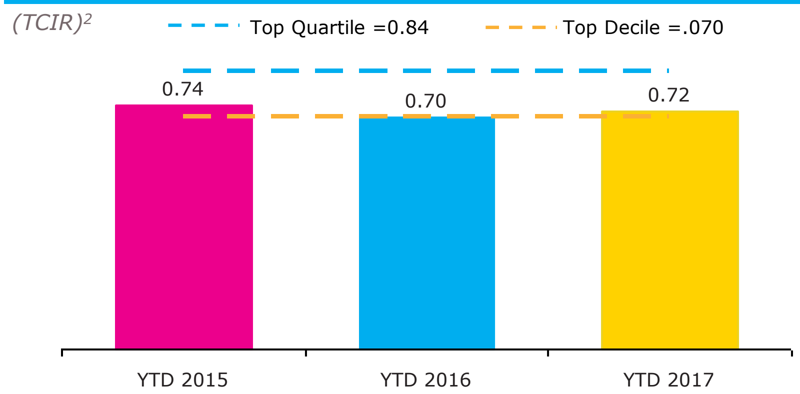
($ millions)	2017	2018	2019	2020 / Run Rate
Accretive & Recurring:				
Cost Savings	65	500	590	590
Margin Enhancement	0	30	135	215
Total EBITDA - Accretion	**$65**	**$530**	**$725**	**$805**
Maintenance Capex	0	30	50	50
Total Recurring FCFbG Accretion	**$65**	**$560**	**$775**	**$855**
Non-Recurring:				
Working Capital Improvement	175	85	110	--
Cost to Achieve Total Transformation Plan	(115)	(175)	--	--
Total Non-Recurring	**$60**	**($90)**	**$110**	**--**
Annual Cash Accretion	**$125**	**$470**	**$885**	**$855**
Cumulative Cash Accretion *(Incremental Capital Available for Allocation)*	**$125**	**$595**	**$1,480**	**$2,335**

Appendix: Operations

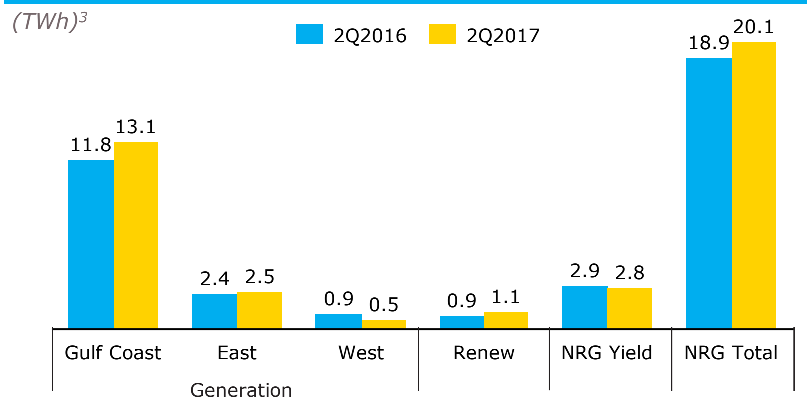
Generation: Operational Metrics

All metrics exclude GenOn

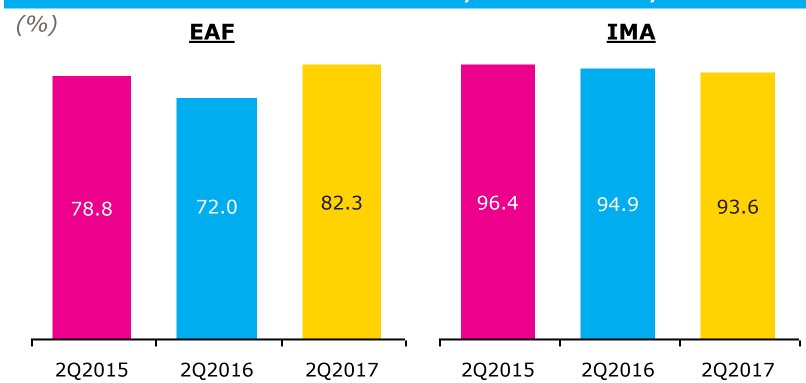
Safety[1]



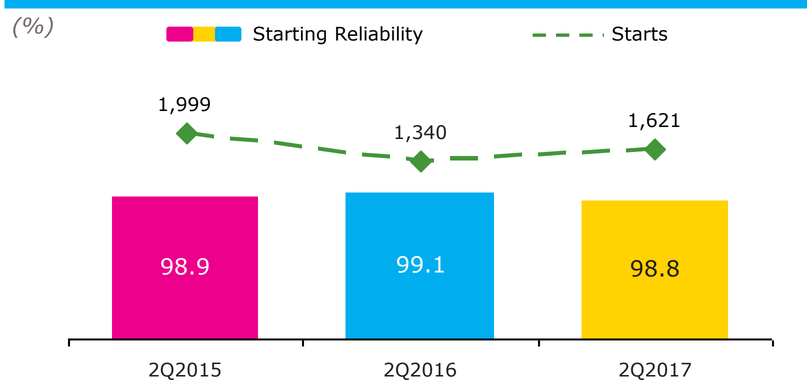
Production



Baseload Equivalent Availability Factor and In-the-Money-Availability



Gas and Oil Starts and Reliability



Higher Total Generation with Strong In The Money Availability

[1] Excludes Goal Zero, NRG Home Services and NRG Home Solar; top decile and top quartile based on Edison Electric Institute 2015 Total Company Survey results; [2] TCIR = Total Case Incident Rate; [3] All NRG-owned domestic generation; excludes line losses, station service, and other items. Generation data presented above consistent with US GAAP accounting. Previous reports were pro-forma for acquisitions in prior periods

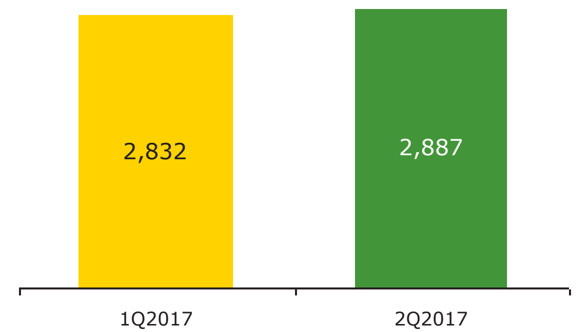
Retail: Operational Metrics

2nd Quarter Highlights

- Delivered $203 MM in Q2 Adjusted EBITDA, slightly lower than last year and consistent with guidance commitment
- Steady volume in the quarter driven by continued growth in mass customer base, despite continued mild weather

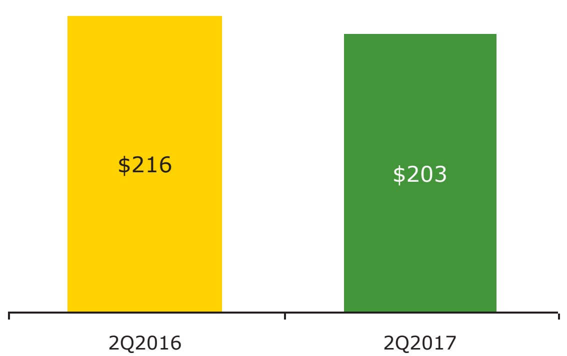
Growth in Q2 Mass Customer Count

Mass Recurring Customers[1] (000s)



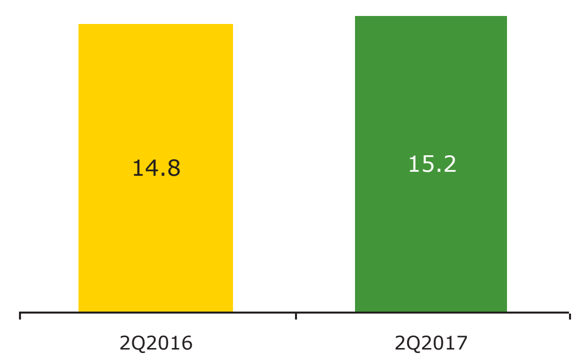
Solid Q2 EBITDA Earnings

Adjusted EBITDA ($ millions)



Steady Q2 Volumes[2]

Delivered TWh



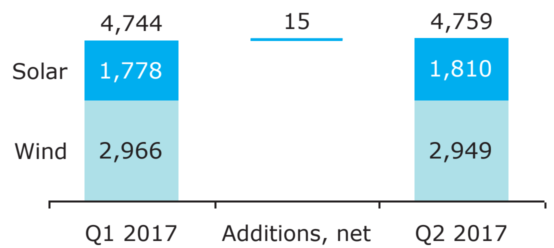
Retail Continuing to Grow Count and Volume, While Remaining on Track for EBITDA Targets

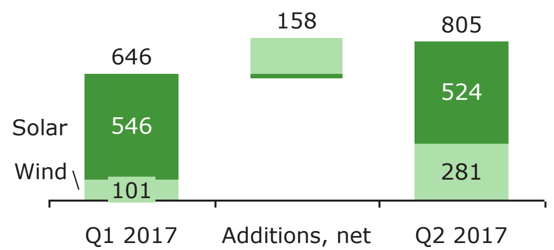
[1] Excludes C&I and NRG Home Solar customers; mass recurring customer count includes customers that subscribe to one or more recurring services, such as electricity and natural gas;
[2] Second quarter sales volumes exclude load associated with customer self-supply

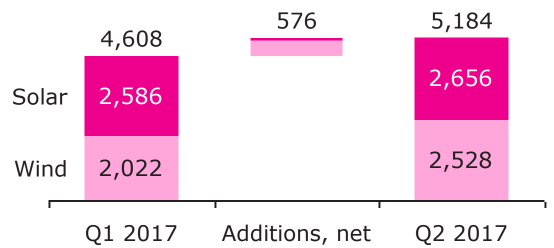
Renewables: Portfolio Update

Quarter over Quarter Change

(MW[1])







Key Q2 Updates

Operating Portfolio: 4,759 MW[1,2,3]

- ☑ 32 MW converted from backlog (15 MW net of non-core divested wind assets[4]) reflects DG and community solar additions across CA, MA, MN, TX
- ☑ Signed Agreement with NYLD for sale of 25% interest in 12 wind projects, 814 MW
- ☑ Offered NYLD 38 MW operational DG portfolio, 82 sites across 6 states
- ☑ Transitioned 2 additional utility solar sites to self operation, reducing annual plant costs by 23%, with 2,757 MW under self operation

2017-2019 Backlog: 805 MW[5]

- ☑ 190 MW converted from pipeline (158 MW net of conversions to operating) reflects additions in utility wind in TX and community solar in NY
- ☑ Commenced construction on 150 MW Texas solar project
- ☑ 345 MW in construction across utility-scale wind and solar, Community, and DG

Utility–Scale and DG Pipeline: 5,184 MW[6]

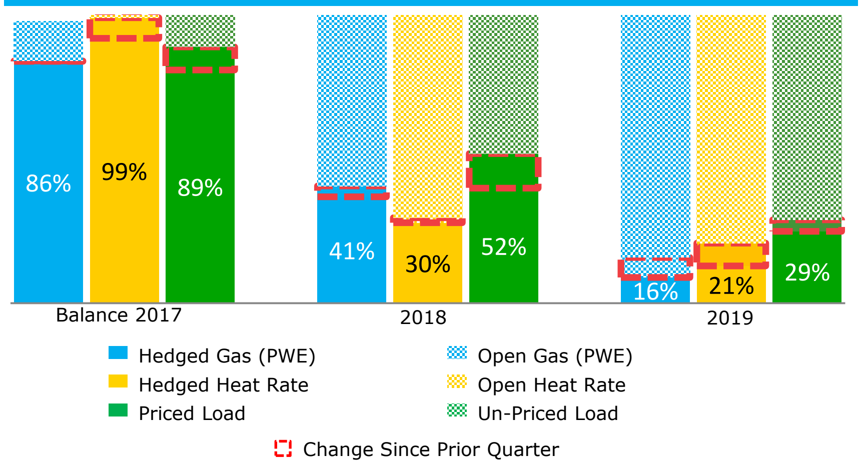
- ☑ 766 MW (576 MW net of conversion to backlog) increase reflects utility scale origination in ERCOT, CAISO, PJM
- ☑ Includes 157 MW of late stage utility scale assets for 2018 execution
- ☑ Community Solar continued expansion across MN and NY
- ☑ DG growth across commercial, municipalities, and schools

Significant Scale and with a Substantial Pipeline for Future Growth

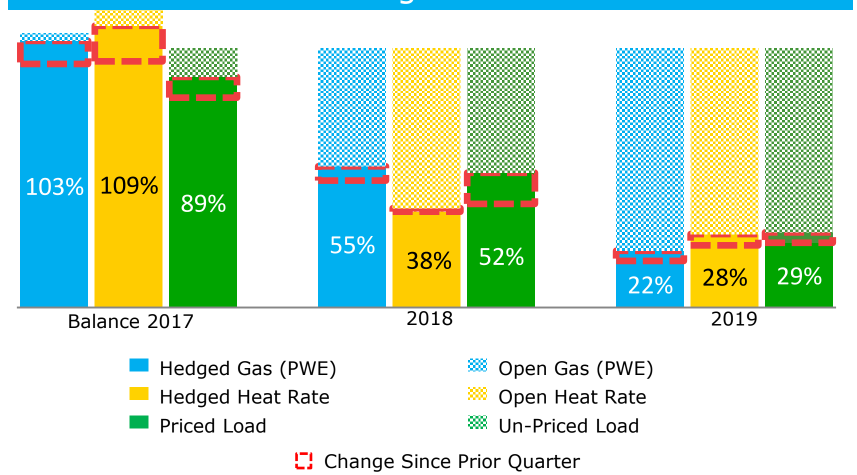
[1] 4.8 GW at NRG Consolidated, of which 2.9 GW is at NRG Yield; [2] MW amounts in AC; [3] NRG self-performs plant operations on 2.8 GW of the consolidated fleet of assets owned by NRG and NRG Yield and 224 MW on assets owned by third parties; [4] Reflects one of the assets in the Minnesota wind portfolio previously offered to and declined by NRG Yield; [5] Backlog is defined as projects that are under construction, contracted, or awarded, and represents a higher level of execution certainty; [6] Pipeline is defined as projects that range from identified lead to shortlisted with an offtake and represents a lower level of execution certainty. Backlog and pipeline data as of July 31, 2017

Managing Commodity Price Risk

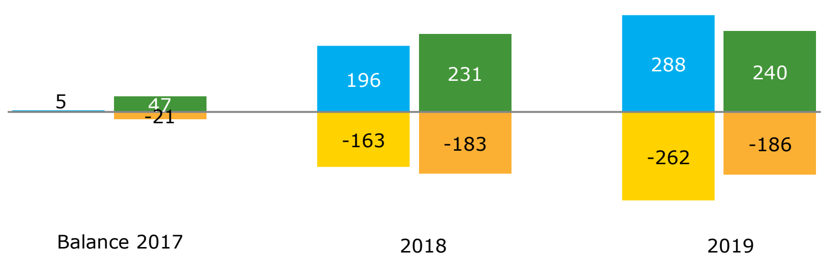
Total Portfolio Generation and Retail Hedge Position[1,2,5]



Coal and Nuclear Generation and Retail Hedge Position[1,2,4]



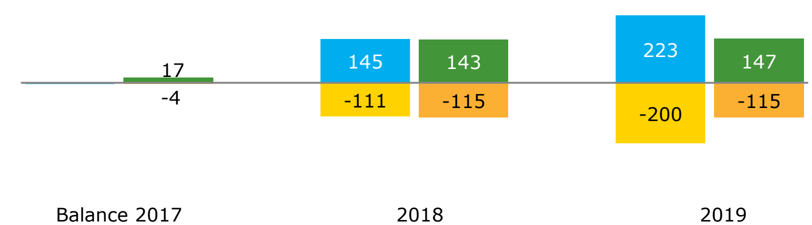
Total Portfolio Sensitivity to Gas Price and Heat Rate[1,3,5]



	Balance 2017	2018	2019
Henry Hub Gas as of 07/26	3.01	2.96	2.80

Gas Up By $0.5/mmBtu
Gas Down By $0.5/mmBtu
HR Up By 1 mmBtu/MWh
HR Down By 1 mmBtu/MWh

Coal and Nuclear Generation Sensitivity to Gas Price and Heat Rate[1,3]



	Balance 2017	2018	2019
Henry Hub Gas as of 07/26	3.01	2.96	2.80

Gas Up By $0.5/mmBtu
Gas Down By $0.5/mmBtu
HR Up By 1 mmBtu/MWh
HR Down By 1 mmBtu/MWh

[1] Portfolio as of 7/26/2017, Balance 2017 reflects July through December; [2] Retail priced load includes term load, Hedged month-to-month load, and Indexed load; [3] Price sensitivity reflects gross margin change from $0.5/MMBtu gas price, 1 mmBtu/MWh heat rate move; [4] Coal hedge ratios are 89% and 51% for 2017 and 2018 respectively; [5] Total Portfolio includes wholesale merchant assets and related hedges

Hedge Disclosure: Coal and Nuclear Operations

Coal & Nuclear Portfolio[1]	Texas and South Central			EAST		
	Balance 2017	2018	2019	Balance 2017	2018	2019
Net Coal and Nuclear Capacity (MW)[2]	6,250	6,250	6,250	3,267	3,267	3,267
Forecasted Coal and Nuclear Capacity (MW)[3]	5,093	4,586	4,478	1,167	1,223	914
Total Coal and Nuclear Sales (GWh)[4]	20,434	22,681	9,015	8,014	5,056	1,335
Percentage Coal and Nuclear Capacity Sold Forward[5]	91%	56%	23%	155%	47%	17%
Total Forward Hedged Revenues[6]	$742	$861	$438	$259	$155	$40
Weighted Average Hedged Price ($ per MWh)[6]	$36.31	$37.95	$48.58	$32.27	$30.58	$29.66
Average Equivalent Natural Gas Price ($ per MMBtu)[6]	$3.29	$3.70	$4.59	$3.23	$3.00	$2.85
Gross Margin Sensitivities $ in MM: Gas Price Sensitivity Up $0.50/MMBtu on Coal and Nuclear Units	($11)	$69	$125	$7	$76	$98
Gas Price Sensitivity Down $0.50/MMBtu on Coal and Nuclear Units	$20	($59)	($142)	$3	($52)	($58)
Heat Rate Sensitivity Up 1 MMBtu/MWh on Coal and Nuclear Units	$11	$97	$93	$7	$46	$53
Heat Rate Sensitivity Down 1 MMBtu/MWh on Coal and Nuclear Units	($3)	($78)	($78)	($1)	($36)	($36)

[1] Portfolio as of 7/26/2017, Balance 2017 reflects July through December
[2] Net Coal and Nuclear capacity represents nominal summer net MW capacity of power generated as adjusted for the Company's ownership position excluding capacity from inactive/mothballed units
[3] Forecasted generation dispatch output (MWh) based on forward price curves as of 7/26/2017 which is then divided by number of hours in a given year to arrive at MW capacity; The dispatch takes into account planned and unplanned outage assumptions
[4] Includes amounts under power sales contracts and natural gas hedges; The forward natural gas quantities are reflected in equivalent GWh based on forward market implied heat rate as of 7/26/2017 and then combined with power sales to arrive at equivalent GWh hedged; The Coal and Nuclear Sales include swaps and delta of options sold which is subject to change; Actual value of options will include the impact of non-linear factors; For detailed information on the Company's hedging methodology through use of derivative instruments, see discussion in 2015 10K Item 15 - Note 5, Accounting for Derivative Instruments and Hedging Activities, to the Consolidated Financial Statements; Includes inter-segment sales from the Company's wholesale power generation business to the Retail Business
[5] Percentage hedged is based on Total Coal and Nuclear sales as described above ([4]) divided by the forecasted Coal and Nuclear Capacity ([3])
[6] Represents all coal and nuclear sales, including energy revenue and demand charges

Commodity Prices

Forward Prices[1]	Bal-2017[2]	2018	2019	Annual Average for 2017-2019
NG Henry Hub ($/MMBtu)	$3.01	$2.96	$2.80	$2.94
PRB 8800 ($/ton)	$11.73	$11.70	$11.85	$11.75
NAPP MG2938 ($/ton)	$43.58	$45.25	$46.50	$45.21
ERCOT Houston On-peak ($/MWh)	$39.33	$36.15	$35.87	$37.23
ERCOT Houston Off-peak ($/MWh)	$25.93	$23.55	$22.39	$24.00
PJM West On-peak ($/MWh)	$33.67	$35.09	$33.44	$34.03
PJM West Off-peak ($/MWh)	$23.89	$25.16	$24.15	$24.38

[1] Prices as of 7/26/2017
[2] Represents July through December months

Fuel Statistics

	2Q		1H	
Domestic[1]	**2017**	**2016**	**2017**	**2016**
Coal Consumed (mm Tons)	6.1	5.7	11.3	9.9
PRB Blend	**94%**	**84%**	**94%**	**83%**
East	99%	99%	98%	96%
Gulf Coast	92%	80%	93%	77%
Bituminous	**<0.5%**	**<0.5%**	**<0.5%**	**1%**
East	1%	1%	2%	4%
Lignite	**6%**	**16%**	**6%**	**16%**
Gulf Coast	8%	20%	7%	23%
Cost of Coal ($/Ton)	**$ 32.21**	**$ 31.62**	**$ 32.33**	**$ 33.19**
Cost of Coal ($/mmBtu)	**$ 1.89**	**$ 1.93**	**$ 1.90**	**$ 2.01**
Cost of Gas ($/mmBtu)	**$ 3.15**	**$ 2.19**	**$ 3.15**	**$ 2.14**

[1] NRG's interests in Keystone and Conemaugh (jointly owned plants) are excluded from the fuel statistics schedule

Q2 2017 Generation & Operational Performance Metrics

(MWh 000s)	2017 Generation[1]	2016 Generation[1]	MWh Change	% Change	2017 EAF[2]	2017 NCF[3]	2016 EAF[2]	2016 NCF[3]
Gulf Coast – Texas	10,089	10,232	(143)	(1%)	87%	44%	94%	44%
Gulf Coast – South Central	3,012	1,538	1,474	96%	83%	39%	81%	20%
East	2,543	2,411	132	5%	76%	12%	66%	11%
West	541	917	(376)	(41%)	88%	13%	93%	22%
Renewables	1,083	901	181	20%	96%	37%	97%	34%
NRG Yield[4]	2,839	2,896	(55)	(2%)	95%	24%	97%	24%
Total	**20,106**	**18,895**	**1,214**	**6%**	**85%**	**28%**	**84%**	**26%**
Gulf Coast – Texas Nuclear	2,098	2,452	(354)	(14%)	83%	82%	97%	95%
Gulf Coast – Texas Coal	6,473	6,001	473	8%	90%	71%	93%	66%
Gulf Coast – South Central Coal	1,004	725	279	38%	75%	37%	73%	45%
East Coal	2,146	1,980	167	8%	77%	22%	46%	20%
Baseload	**11,722**	**11,158**	**564**	**5%**	**83%**	**49%**	**72%**	**48%**
Renewables Solar	551	432	118	27%	98%	39%	100%	59%
Renewables Wind	532	469	63	13%	95%	37%	96%	29%
NRG Yield Solar	379	386	(7)	(2%)	99%	39%	99%	40%
NRG Yield Wind	1,709	1,655	54	3%	96%	38%	97%	37%
Intermittent	**3,171**	**2,942**	**229**	**8%**	**97%**	**38%**	**97%**	**36%**
East Oil	18	12	6	48%	76%	0%	86%	0%
Gulf Coast – Texas Gas	1,517	1,779	(262)	(15%)	85%	14%	95%	15%
Gulf Coast – South Central Gas	2,008	813	1,196	147%	89%	35%	86%	14%
East Gas	379	419	(40)	(10%)	73%	6%	64%	6%
West Gas	541	917	(376)	(41%)	88%	13%	93%	22%
NRG Yield Conventional	313	376	(63)	(17%)	94%	7%	98%	9%
NRG Yield Thermal	438	480	(40)	(8%)	89%	4%	81%	9%
Intermediate / Peaking	**5,214**	**4,795**	**421**	**9%**	**83%**	**12%**	**86%**	**11%**

[1] Excludes line losses, station service and other items; [2] EAF – Equivalent Availability Factor; [3] NCF – Net Capacity Factor; [4] Includes MWh (thermal heating & chilled water generation); NCF not inclusive of MWht

YTD 2017 Generation & Operational Performance Metrics

(MWh 000s)	2017 Generation[1]	2016 Generation[1]	MWh Change	% Change	2017 EAF[2]	2017 NCF[3]	2016 EAF[2]	2016 NCF[3]
Gulf Coast – Texas	17,810	16,798	1,012	6%	86%	39%	91%	36%
Gulf Coast – South Central	5,980	4,703	1,278	27%	86%	39%	87%	30%
East	5,048	5,676	(628)	(11%)	84%	12%	72%	13%
West	1,053	1,631	(578)	(35%)	86%	13%	88%	20%
Renewables	2,013	1,991	22	1%	96%	36%	97%	39%
NRG Yield[4]	5,229	5,580	(349)	(6%)	94%	22%	95%	23%
Total	**37,132**	**36,377**	**757**	**2%**	**87%**	**26%**	**85%**	**25%**
Gulf Coast – Texas Nuclear	4,418	4,954	(537)	(11%)	88%	86%	98%	96%
Gulf Coast – Texas Coal	11,488	9,099	2,389	26%	92%	63%	87%	50%
Gulf Coast – South Central Coal	1,969	1,145	824	72%	82%	36%	82%	44%
East Coal	4,449	5,095	(646)	(13%)	85%	23%	55%	25%
Baseload	**22,323**	**20,293**	**2,031**	**10%**	**87%**	**46%**	**74%**	**44%**
Renewables Solar	876	812	65	8%	99%	40%	100%	54%
Renewables Wind	1,136	1,179	(43)	(4%)	96%	35%	96%	36%
NRG Yield Solar	592	633	(40)	(6%)	99%	30%	100%	32%
NRG Yield Wind	3,158	3,187	(28)	(1%)	97%	38%	98%	36%
Intermittent	**5,763**	**5,810**	**(46)**	**(1%)**	**97%**	**36%**	**98%**	**36%**
East Oil	43	33	11	32%	84%	0%	90%	0%
Gulf Coast – Texas Gas	1,904	2,745	(841)	(31%)	81%	8%	92%	12%
Gulf Coast – South Central Gas	4,012	3,558	454	13%	90%	35%	90%	31%
East Gas	556	548	8	1%	83%	4%	72%	5%
West Gas	1,053	1,631	(578)	(35%)	86%	13%	88%	20%
NRG Yield Conventional	455	637	(182)	(29%)	89%	5%	92%	7%
NRG Yield Thermal	1,023	1,124	(98)	(9%)	94%	4%	90%	21%
Intermediate / Peaking	**9,046**	**10,274**	**(1,227)**	**(12%)**	**85%**	**10%**	**87%**	**12%**

[1] Excludes line losses, station service and other items; [2] EAF – Equivalent Availability Factor; [3] NCF – Net Capacity Factor; [4] Includes MWh (thermal heating & chilled water generation); NCF not inclusive of MWht

In the Money Availability Calculation

"In the Money Availability" (IMA) is an NRG performance measurement leveraging Generating Availability Data System (GADS) data and market prices to calculate the percentage of generation available during periods when market prices allow these units to be dispatched profitably.

- Transitioning from Equivalent Availability Factor (EAF) to IMA allows us to measure our availability during the greatest opportunities to capture value. IMA performance measurement bridges operational performance to shareholder value.
- IMA uses similar approach as GADS EAF calculation:

$$\textbf{EAF} = \frac{\textbf{Avail Hours} - \textbf{All Eq. Unplanned Outage Hrs}}{\textbf{Period Hours}} \times 100$$

$$\textbf{IMA} = \frac{\textbf{IMA Avail Hours} - \textbf{IMA Eq Lost Margin Hrs}}{\textbf{IMA Avail Hours}} \times 100$$

- Factors that impact IMA include forced outages, derates, maintenance, and/or extensions to planned and unplanned outages, when a unit is in the money; reserve shutdown hours (SH) are not included
- IMA "Available Hours" equals period hours less planned outage hours and uneconomic hours when an unplanned curtailing event occurs
- IMA "Equivalent Lost Margin Hours" (ELMH) are calculated similarly Equivalent Unplanned Outage Hours (EUOH) used for EAF
  - If there is lost margin during the hour of the curtailing event, the hour is be included as both an IMA Available Hour and an IMA ELMH
  - If there is zero lost margin during the hour of the curtailing event, the hour is not included in the available hour count AND the ELMH would be zero for that hour

PJM Capacity Clears: NRG Standalone

PJM Region	Planning Year	Average Price ($/MW-day)[1]	MWs Cleared	Average Price ($/MW-day)[1]	MWs Cleared
		Base Product		Capacity Performance Product	
ComEd	2017-2018	$145.51	539	$151.50	3,227
	2018-2019	$25.36	225	$215.00	3,509
	2019-2020	$182.77	65	$202.77	3,738
	2020-2021			$188.12	3,315
MAAC	2017-2018	$116.96	17	$151.50	106
	2018-2019	$149.98	1	$164.77	108
	2019-2020	$80.00	1	$100.00	105
	2020-2021			$86.04	91
EMAAC	2017-2018	NA	NA	NA	NA
	2018-2019	NA	NA	NA	NA
	2019-2020	NA	NA	NA	NA
	2020-2021			NA	NA
DPL South	2017-2018	$150.03	133	$151.50	358
	2018-2019	$210.63	98	$225.42	459
	2019-2020	NA	NA	$119.77	481
	2020-2021			$187.87	519
PEPCO	2017-2018	$111.13	80	NA	NA
	2018-2019	NA	NA	$164.77	69
	2019-2020	NA	NA	$100.00	66
	2020-2021			$86.04	67
ATSI	2017-2018	NA	NA	NA	NA
	2018-2019	NA	NA	NA	NA
	2019-2020	NA	NA	NA	NA
	2020-2021			NA	NA
RTO	2017-2018	$126.13	907	$151.50	9
	2018-2019	NA	NA	NA	NA
	2019-2020	NA	NA	NA	NA
	2020-2021			NA	NA
Net Total	2017-2018	$133.46	1,676	$151.50	3,701
	2018-2019	$81.75	324	$227.69	4,144
	2019-2020	$181.51	65	$189.69	4,389
	2020-2021			$184.04	3,992

PJM Capacity Revenue by Delivery Year

($ MM)	NRG
17/18	$286
18/19	$354
19/20	$309
20/21	$268

PJM Capacity Revenue by Calendar Year

($ MM)	NRG
2017	$247
2018	$326
2019	$327
2020	$286

Assumptions:

- Data as of 5/23/2017
- Includes imports
- Excludes NRG Yield Assets
- Represents merchant wholesale generation

[1] Average Price ($/MW-day) can vary from stated BRA cleared auction price due to MWs purchased or sold in incremental auctions

PJM Asset List: Merchant Wholesale Generation

Net Generating Capacity by LDA

COMED (4,336 MW)				
Name	Location	Capacity	Entity	Ownership %
Fisk	Chicago, IL	172	NRG	100.0%
Joliet	Joliet, IL	1,326	NRG	100.0%
Powerton	Pekin, IL	1,538	NRG	100.0%
Waukegan	Waukegan, IL	790	NRG	100.0%
Will County	Romeoville, IL	510	NRG	100.0%

DPL (593 MW)				
Name	Location	Capacity	Entity	Ownership %
Indian River	Millsboro, DE	426	NRG	100.0%
Vienna	Vienna, MD	167	NRG	100.0%

MAAC (126 MW)				
Name	Location	Capacity	Entity	Ownership %
Conemaugh	New Florence, PA	63	NRG	3.72%
Keystone	Shelocta, PA	63	NRG	3.70%

PEPCO (78 MW)				
Name	Location	Capacity	Entity	Ownership %
SMECO	Prince Georges County, MD	78	NRG	100.0%

Assumptions:

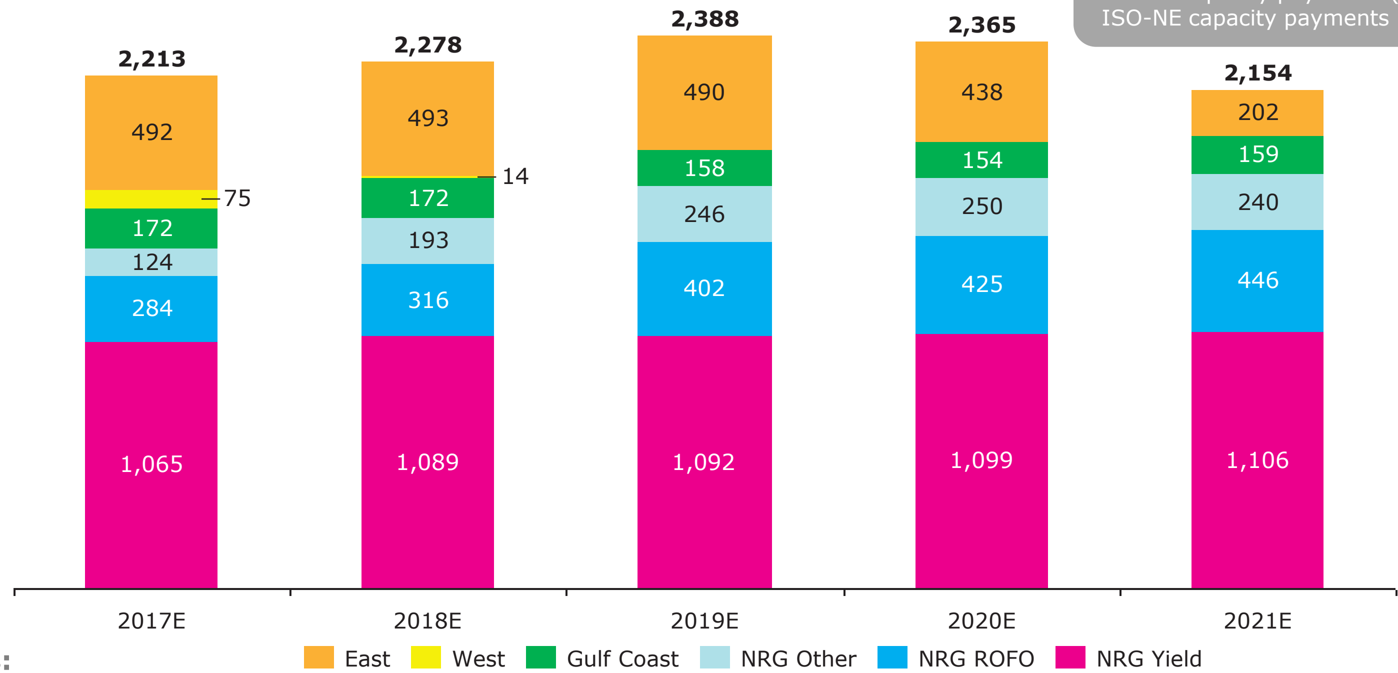
- ❖ Data reflects physical location of generating unit; reflects demonstrated summer capacity with NRG's ownership applied, including conversions
- ❖ Excludes NYLD assets Dover 104 MW in DPL and Paxton Creek 12 MW in MAAC
- ❖ Data as of 6/30/2017

Appendix: Finance

Fixed Contracted and Capacity Revenue (2Q17)

($ millions)

Excludes Penalties and Uncleared:
NYISO capacity payments (post 2018)
PJM capacity payments (post 20/21 BRA)
ISO-NE capacity payments (post 20/21 FCA11)



Notes:

- East includes cleared capacity auction for PJM through May 2021, New England ISO Forward Capacity Auction 11 (FCA11) through May 2021; NY on rolling forward basis
- West includes committed Resource Adequacy contracts & tolling agreements
- Gulf Coast region includes South Central capacity sold into PJM/MISO auctions and Co-Op contracted revenues. Co-Op contracted revenues are also incorporated in the hedge table
- NRG ROFO includes all wind, solar and conventional assets which are part of ROFO agreement including projects under construction (Carlsbad and Puente)
- NRG Other includes renewable assets which are not part of ROFO and preferred resources projects
- NRG Yield includes contracted capacity, contracted energy and contracted steam revenues

YTD 2Q17 Net Capital Expenditures

($ millions)	Maintenance	Environmental	Growth	Total
Generation				
Gulf Coast[1]	$53	$1	$3	$57
East/West[2]	16	24	181	221
Retail	14	-	13	27
Renewables	2	-	213	215
NRG Yield	11	-	2	13
Corporate	6	-	3	9
Total Cash Capital Expenditures	**$102**	**$25**	**$415**	**$542**
Other Investments[3]	-	-	66	66
Project Funding, net of fees[4]	-	-	(593)	(593)
Total Capital Expenditures and Growth Investments, net	**$102**	**$25**	**($112)**	**$15**

[1] Excludes $18 MM of insurance proceeds on maintenance capex; [2] Also includes International and BETM. Includes growth capital spend related to Carlsbad; [3] Includes investments and acquisitions; [4] Includes net debt proceeds, cash grants and third-party contributions

Growth Investments and Capex, Net of Financing

($ millions)	2017E	2018E[1]
NRG Level		
Growth	85	155
Environmental	35	1
Maintenance	188	155
Other[2]		
Growth	2	-
Environmental	-	-
Maintenance	35	-

[1] Pro forma for asset divestitures and cost reductions per Transformation Call on July 12, 2017; [2] Other includes NRG Yield, Ivanpah, and Agua Caliente

Generation Organizational Structure

NRG Energy, Inc. (30,540[1] MW)

Renewables (1,135 MW)

Solar
- Agua Caliente[2]
- Blythe II
- Community Solar
- Distributed Solar
- Guam
- Ivanpah
- Spanish Town
- Stadiums

Wind
- Bingham Lake
- Broken Bow
- Cedro Hill
- Community Wind
- Crofton Bluffs
- Eastridge
- Jeffers
- Langford
- Mountain Wind I&II
- Sherbino

NRG Yield[3] (2,756 MW)

- Alta Wind
- Alpine
- Avenal
- Avra Valley
- Blythe
- Borrego
- Buffalo Bear
- Crosswinds
- CVSR
- Desert Sunlight
- Distributed Solar
- Dover
- El Segundo
- Elbow Creek
- Elkhorn Ridge
- Forward
- GenConn Devon
- GenConn Middletown
- Goat Wind
- Hardin
- High Desert
- Kansas South
- Laredo Ridge
- Lookout
- Marsh Landing
- Odin
- Paxton Creek
- Pinnacle
- Princeton
- Roadrunner
- San Juan Mesa
- South Trent
- Spanish Fork
- Spring Canyon II & III
- Sleeping Bear
- Taloga
- Tucson
- Univ. of Bridgeport
- Walnut Creek
- Wildorado

Drop down to NRG Yield on March 27, 2017:
- Agua Caliente[2]
- Four Brothers[4]
- Granite Mountain[4]
- Iron Springs[4]

Gulf Coast (14,063 MW)

Texas (10,508 MW)
- Cedar Bayou
- Cedar Bayou 4
- Greens Bayou
- Gregory
- Limestone
- San Jacinto
- South Texas Project
- TH Wharton
- WA Parish

South Central (3,555 MW)
- Bayou Cove
- Big Cajun I
- Big Cajun II
- Cottonwood
- Sterlington

Other Conventional (22 MW)

- Petra Nova Cogen

West (2,129 MW)

- Encina
- Long Beach
- Midway Sunset
- Saguaro
- San Diego Jet
- Sunrise
- Watson

Residential Solar (114 MW)

Other (749 MW)

- Doga
- Gladstone

East (9,572 MW)

- Arthur Kill
- Astoria
- Conemaugh
- Connecticut Jets
- Devon
- Fisk
- Indian River
- Joliet
- Keystone
- Middletown
- Montville
- Oswego
- Powerton
- SMECO
- Vienna
- Waukegan
- Will County

LEGEND
- Separate Credit Facility (green dotted box)
- drop down to NRG Yield on March 27, 2017 (pink box)
- Equity Investments (underlined)

[1] Capacity controlled by NRG as of 6/30/2017, excluding GenOn; [2] Agua Caliente is 51% owned by NRG Consolidated, of which 16% is owned by NRG Yield; [3] Projects in NRG Wind TE Holdco are owned 75% by NRG Yield and 25% by NRG; as of August 1,2017 NRG Yield owns 100% of these assets; [4] Four Brothers, Granite Mountain, and Iron Springs are 50% owned by NRG Yield

Consolidated Debt Structure
as of 6/30/2017

($ millions)

LEGEND
- Recourse Debt
- Non-Recourse Debt
- SEC Filer

NRG Energy, Inc.

Revolver $2.5 BN due 2018/2021[1]	$	0
Senior notes due 2018-2027		5,449
Term loan due 2023		1,881
Tax exempt bonds due 2038-2045		455
Capital Lease		6
Total	**$**	**7,791**

Conventional Financings

Other non-recourse debt		7

Midwest Generation

Capacity Monetization/ Operating leases[2]	$	194

Carlsbad Energy

Term Loan	$	345

Agua Caliente

Project financing due 2037	$	843
Borrower 1 due 2038		89

Ivanpah

Promissory Note and Project financing due 2033 and 2038		1,175

Other Renewables Financings

Project financings	$	704

NRG Yield, Inc.

Senior convertible notes due 2019-2020	$	633

NRG Yield Operating LLC

Revolver $495 MM due 2019[3]	$	0
Green Bond notes		500
Senior Notes Due 2026		350

Conventional

Term loans due 2017 & 2023	$	1,116

Thermal

Senior secured notes due 2017-2025 and 2031	$	209

Renewable

Project financings[4]	$	3,175

Note: Debt balances exclude discounts and premiums
[1] $1,039 MM LC's issued and $1,482 MM Revolver available at NRG; [2] The present value of lease payments (9.1% discount rate) for Midwest Generation operating lease is $88 MM; this lease is guaranteed by NRG Energy, Inc.; [3] $68 MM of LC's were issued and $427 MM of the Revolver was available at NRG Yield; [4] Includes Four Brothers Holdings, Iron Springs Renewables, and Granite Mountain Renewables following the drop down on 3/27/2017

Recourse / Non-Recourse Debt

($ millions)	6/30/2017	3/31/2017	12/31/2016	9/30/2016
Recourse Debt				
Term Loan Facility	$ 1,881	$ 1,886	$ 1,891	$ 1,895
Senior Notes	5,449	5,449	5,449	5,827
Tax Exempt Bonds	455	455	455	455
Revolver	-	125	-	-
Capital Lease	6	8	-	-
Recourse Debt Subtotal	**$ 7,791**	**$ 7,923**	**$ 7,795**	**$ 8,177**
Non-Recourse Debt				
Total NRG Yield[1,2]	$ 5,983	$ 6,051	$ 6,085	$ 5,733
Renewables (including capital leases)[2]	2,811	2,661	2,592	2,586
Conventional	546	220	238	257
Non-Recourse Debt and Capital Lease Subtotal	**$ 9,340**	**$ 8,932**	**$ 8,915**	**$ 8,576**
Total Debt	**$ 17,131**	**$ 16,855**	**$ 16,710**	**$ 16,753**

Note: Debt balances exclude discounts and premiums
[1] Includes convertible notes and project financings, including $179 MM related to Viento - NRG owns 25% of the project; [2] NRG Yield has been recast following the CVSR drop down on 9/01/2016 and the Four Brothers, Iron Springs, and Granite Mountain drop down on 3/27/2017

Schedule of Debt Maturities

$ in millions as of June 30, 2017 Issuance	Maturity Year	NRG Recourse	Yield Non-Recourse
7.625% NRG Senior Notes	**2018**	**$398**	**$-**
3.5% NRG Yield Inc. Convertible Notes	**2019**	**-**	**345**
3.25% NRG Yield Convertible Notes	**2020**	**-**	**288**
7.875% NRG Senior Notes	**2021**	**207**	**-**
4.750% Tax Exempt Bonds	2022	54	-
6.25% NRG Senior Notes	2022	992	-
	2022 Total	**1,046**	-
NRG Term Loan	2023	1,881	-
6.625% NRG Senior Notes	2023	869	-
	2023 Total	**2,750**	-
6.25% NRG Senior Notes	2024	733	-
5.375% NRG Yield Operating LLC Senior Notes	2024	-	500
	2024 Total	**733**	**500**
7.25% NRG Senior Notes	2026	1,000	-
5% NRG Yield Operating LLC Senior Notes	2026	-	350
	2026 Total	**1,000**	**350**
6.625% NRG Senior Notes	**2027**	**1,250**	**-**
6.0% Tax Exempt Bonds	**2040**	**57**	**-**
4.125% Tax Exempt Bonds	2042	22	-
4.750% Tax Exempt Bonds	2042	73	-
5.875% Tax Exempt Bonds	2042	59	-
	2042 Total	**154**	**-**
5.375% Tax Exempt Bonds	**2045**	**190**	**-**
	Subtotal	**7,785**	**1,483**
Capital Leases and Non-Recourse Project Debt[1]	**Various**	**6**	**4,500**
Total Debt		**7,791**	**5,983**

Note: Debt balances exclude discounts and premiums

[1] Includes project-level debt and capital leases that are non-recourse to NRG and NRG Yield

Appendix:
Reg. G Schedules

Reg. G: YTD 2Q17 Free Cash Flow before Growth

($ millions)	YTD 6/30/2017
Adjusted EBITDAR	**$ 1,082**
Less: EME operating lease expense	(11)
Adjusted EBITDA	**$ 1,071**
Interest payments	(413)
Income tax	(7)
Collateral / working capital / other[1]	(539)
Cash Flow from Operations	**$ 112**
Reclassifying of net receipts (payments) for settlement of acquired derivatives that include financing elements	2
Land Sale	8
Return of capital from equity investments[2]	18
Collateral[1]	268
Adjusted Cash Flow from Operations	**$ 408**
Maintenance capital expenditures, net [3]	(84)
Environmental capital expenditures, net	(25)
Distributions to non-controlling interests	(91)
Consolidated Free Cash Flow before Growth	**$ 208**
Less: FCFbG at Non-Guarantor Subsidiaries[4]	(79)
NRG-Level Free Cash Flow before Growth	**$ 129**

[1] Reflects change in NRG's cash collateral balance as of 2Q2017 including $79MM of collateral postings from our deconsolidated affiliate (GenOn); [2] Represents cash distributions to NRG from equity investments; [3] Includes insurance proceeds of $18 MM; [4] Reflects impact from NRG Yield and other excluded project subsidiaries

Reg. G: 2017 Guidance

Appendix Table A-1: 2017 Guidance

The following table summarizes the calculation of Free Cash Flow before Growth and provides a reconciliation to Adjusted EBITDA

($ millions)	Previous Guidance	Revised Guidance
Adjusted EBITDA	**$2,700 - $2,900**	**$2,565 - $2,765**
Interest payments	(1,065)	(825)
Income tax	(40)	(40)
Working capital / other	(240)	60
Adjusted Cash Flow from Operations	**$1,355 - $1,555**	**$1,760 - $1,960**
Maintenance capital expenditures, net	(280) - (310)	(210) - (240)
Environmental capital expenditures, net	(40) - (60)	(25) - (45)
Distributions to non-controlling interests[1]	(185) – (205)	(185) – (205)
Consolidated Free Cash Flow before Growth	**$800 - $1,000**	**$1,290 - $1,490**
Less: FCFbG at Non-Guarantor Subsidiaries[2]	(100)	(420)
NRG-Level Free Cash Flow before Growth	**$700 - $900**	**$870 - $1,070**

[1] Includes NRG Yield distributions to public shareholders, and Capistrano and Solar distributions to non-controlling interests; [2] Reflects impact from NRG Yield and other excluded project subsidiaries

Reg. G

Appendix Table A-2: Second Quarter 2017 Adjusted EBITDA Reconciliation by Operating Segment

The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to (Loss)/Income from Continuing Operations

($ millions)	Gulf Coast	East/ West [1]	Generation	Retail	Renewables	NRG Yield	Corp/ Elim	Total
(Loss)/Income from Continuing Operations	**(148)**	**58**	**(90)**	**341**	**(47)**	**45**	**(150)**	**99**
Plus:								
Interest expense, net	-	8	8	1	29	84	122	244
Income tax	(2)	3	1	(11)	(5)	8	11	4
Loss on debt extinguishment	-	-	-	-	-	-	-	-
Depreciation and amortization	69	26	95	29	50	78	8	260
ARO Expense	4	2	6	-	1	1	(1)	7
Amortization of contracts	4	1	5	-	-	17	-	22
Amortization of leases	-	(2)	(2)	-	-	-	-	(2)
EBITDA	**(73)**	**96**	**23**	**360**	**28**	**233**	**(10)**	**634**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	15	5	20	(3)	(5)	34	1	47
Acquisition-related transaction & integration costs	(10)	-	(10)	-	-	1	-	(9)
Reorganization costs	-	-	-	-	-	-	9	9
Deactivation costs	-	(1)	(1)	-	-	-	5	4
Other non recurring charges	(13)	(3)	(16)	2	8	2	-	(4)
Impairments	41	-	41	-	22	-	-	63
Mark to market (MtM) (gains)/losses on economic hedges	105	(11)	94	(156)	3	-	-	(59)
Adjusted EBITDA	**65**	**87**	**152**	**203**	**56**	**270**	**4**	**685**

[1] Includes International, BETM and generation eliminations

Reg. G

Appendix Table A-3: Second Quarter 2016 Adjusted EBITDA Reconciliation by Operating Segment

The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to (Loss)/Income from Continuing Operations

($ millions)	Gulf Coast	East/ West [1]	Generation	Retail	Renewables	NRG Yield	Corp/ Elim	Total
(Loss)/Income from Continuing Operations	**(341)**	**(117)**	**(458)**	**657**	**(71)**	**64**	**(355)**	**(163)**
Plus:								
Interest expense, net	-	11	11	-	24	68	133	236
Income tax	-	-	-	-	(4)	12	17	25
Loss on debt extinguishment	-	-	-	-	-	-	80	80
Depreciation and amortization	70	27	97	29	47	75	14	262
ARO Expense	3	4	7	-	-	-	-	7
Amortization of contracts	3	1	4	2	-	17	-	23
Amortization of leases	-	(2)	(2)	-	-	-	-	(2)
EBITDA	**(265)**	**(76)**	**(341)**	**688**	**(4)**	**236**	**(111)**	**468**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	2	6	8	-	2	18	4	32
Acquisition-related transaction & integration costs	-	1	1	-	-	-	4	5
Reorganization costs	-	-	-	-	1	-	8	9
Deactivation costs	-	5	5	-	-	-	-	5
Loss on sale of business	-	-	-	-	-	-	83	83
Other non-recurring charges	9	(1)	8	2	5	3	(11)	7
Impairments	-	17	17	-	27	-	12	56
Mark to market (MtM) (gains)/losses on economic hedges	389	116	505	(474)	2	-	-	33
Adjusted EBITDA	**135**	**68**	**203**	**216**	**33**	**257**	**(11)**	**698**

[1] Includes International, BETM and generation eliminations

Reg. G

Appendix Table A-4: YTD Second Quarter 2017 Adjusted EBITDA Reconciliation by Operating Segment
The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to (Loss)/Income from Continuing Operations

($ millions)	Gulf Coast	East/ West [1]	Generation	Retail	Renewables	NRG Yield	Corp/ Elim	Total
(Loss)/Income from Continuing Operations	**(105)**	**49**	**(56)**	**311**	**(79)**	**44**	**(290)**	**(70)**
Plus:								
Interest expense, net	-	17	17	3	50	160	236	466
Income tax	-	2	2	(8)	(10)	7	8	(1)
Loss on debt extinguishment	-	-	-	-	2	-	-	2
Depreciation and amortization	138	54	192	57	99	153	16	517
ARO Expense	7	6	13	-	1	2	-	16
Amortization of contracts	8	2	10	1	-	34	-	45
Amortization of leases	-	(4)	(4)	-	-	-	-	(4)
EBITDA	**48**	**126**	**174**	**364**	**63**	**400**	**(30)**	**971**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	21	12	33	(6)	(10)	47	1	65
Acquisition-related transaction & integration costs	(10)	-	(10)	-	-	2	-	(8)
Reorganization costs	-	-	-	-	-	-	16	16
Deactivation costs	-	1	1	-	-	-	4	5
Other non-recurring charges	(13)	(3)	(16)	(2)	10	5	3	-
Impairments	41	-	41	-	22	-	-	63
Mark to market (MtM) (gains)/losses on economic hedges	(17)	(1)	(18)	(20)	(3)	-	-	(41)
Adjusted EBITDA	**70**	**135**	**205**	**336**	**82**	**454**	**(6)**	**1,071**

[1] Includes International, BETM and generation eliminations

Reg. G

Appendix Table A-5: YTD Second Quarter 2016 Adjusted EBITDA Reconciliation by Operating Segment
The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to net (loss)/income

($ millions)	Gulf Coast	East/ West [1]	Generation	Retail	Renewables	NRG Yield	Corp/ Elim	Total
Net (loss)/income	**(471)**	**38**	**(433)**	**807**	**(111)**	**66**	**(549)**	**(220)**
Plus:								
Interest expense, net	-	17	17	-	51	142	266	476
Income tax	-	-	-	1	(11)	12	45	47
Loss on debt extinguishment	-	-	-	-	-	-	69	69
Depreciation and amortization	143	54	197	57	95	149	30	528
ARO Expense	5	8	13	-	1	1	(1)	14
Amortization of contracts	6	4	10	4	-	40	(2)	52
Amortization of leases	-	(4)	(4)	-	-	-	-	(4)
EBITDA	**(317)**	**117**	**(200)**	**869**	**25**	**410**	**(142)**	**962**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	5	12	17	-	2	42	5	66
Acquisition-related transaction & integration costs	-	1	1	-	-	-	6	7
Reorganization costs	1	-	1	5	3	-	10	19
Deactivation costs	-	13	13	-	-	-	-	13
Loss on sale of business	-	-	-	-	-	-	83	83
Other non-recurring charges	10	(4)	6	6	7	3	-	22
Impairments	-	17	17	-	27	-	12	56
Impairment loss on investments	137	-	137	-	-	-	2	139
Mark to market (MtM) (gains)/losses on economic hedges	414	65	479	(508)	1	-	-	(28)
Adjusted EBITDA	**250**	**221**	**471**	**372**	**65**	**455**	**(24)**	**1,339**

[1] Includes International, BETM and generation eliminations

Reg. G

Appendix Table A-6: Expected Full Year 2017 Free Cash Flow before Growth Reconciliation for GenOn Energy, Inc., and NRG Yield (NYLD) / Other[1]: The following table summarizes the calculation of Free Cash Flow before Growth and provides a reconciliation to Adjusted EBITDA

($ millions)	2017 FY		
	Genon	NYLD /Other	Total
Adjusted EBITDA	**130**	**1,265**	**1,395**
Interest payments	(240)	(350)	(590)
Collateral / working capital / other	(125)	(143)	(268)
Cash Flow from Operations	**(235)**	**772**	**537**
Maintenance capital expenditures, net	(70)	(35)	(105)
Environmental capital expenditures, net	(15)	-	(15)
Distributions to NRG	-	(142)	(142)
Distributions to non-controlling interests	-	(175)	(175)
Free Cash Flow before Growth	**(320)**	**420**	**100**

[1] Includes NRG Yield and other assets (primarily Aqua Caliente, Ivanpah, and Capistrano)

Reg. G

Appendix Table A-7: Adjusted EBITDA Guidance Reconciliation: The following table summarizes the calculation of Adjusted EBITDA providing reconciliation to net income:

	2017 Adjusted EBITDA Previous Guidance		2017 Adjusted EBITDA Revised Guidance	
($ millions)	**Low**	**High**	**Low**	**High**
GAAP Net Income [1]	150	350	360	560
Income tax	80	80	80	80
Interest Expense and Debt Extinguishment Costs	1,065	1,065	825	825
Depreciation, Amortization, Contract Amortization and ARO Expense	1,235	1,235	1,150	1,150
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	110	110	110	110
Other Costs [2]	60	60	40	40
Adjusted EBITDA	**$2,700**	**$2,900**	**$2,565**	**$2,765**

[1] For purposes of guidance, fair value accounting related to derivatives are assumed to be zero; [2] Includes deactivation costs, gain on sale of businesses, asset write-offs, impairments and eVgo California settlement

Reg. G

Appendix Table A-8: Expected Full Year 2017 Adjusted EBITDA Reconciliation for GenOn Energy, Inc., ROFO/ Renewable/Conventional[1,2], and NRG Yield[2]

The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to net (loss)/income

($ millions)	Genon	ROFO/Renewable/ Convention	NRG Yield
Net (loss)/income	**(161)**	**53**	**140**
Plus:			
Income tax	-	(5)	25
Interest expense, net	186	88	290
Depreciation, Amortization, Contract Amortization, and ARO Expense	133	198	381
EBITDA	**158**	**334**	**836**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	-	(10)	80
Deactivation costs	22	-	-
Other non-recurring charges	-	-	4
Mark to market (MtM) losses on economic hedges	(50)	21	-
Plus: Operating lease expense	112	21	-
Adjusted EBITDAR	**242**	**366**	**920[3]**
Less: Operating lease expense	(112)	(21)	-
Adjusted EBITDA - Standalone	**130**	**345**	**920**
Shared services	190		
Consolidated Adjusted EBITDA Contribution	**320**		

[1] In accordance with GAAP, restated to reflect impact of Utah Solar and NRG's 31% interest in Agua Caliente drop down to NRG Yield; [2] Guidance as of the NRG Yield 1Q 2017 earnings call

Reg. G

Appendix Table A-9: Prior 6 quarters Adjusted EBITDA Reconciliation for NRG post deconsolidation of GenOn Energy
The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to (Loss)/Income from Continuing Operations

($ millions)	1Q 2016	2Q 2016	3Q 2016	4Q 2016	1Q 2017	2Q 2017
(Loss)/Income from Continuing Operations	**(57)**	**(163)**	**128**	**(892)**	**(170)**	**99**
Plus:						
Income tax	22	25	28	(70)	(4)	4
Interest expense, net	240	236	234	176	222	244
Loss on debt extinguishment	(11)	80	50	23	2	0
Depreciation, Amortization, Contract Amortization, and ARO Expense	300	290	318	374	286	287
EBITDA	**494**	**468**	**758**	**(389)**	**336**	**634**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	33	32	28	14	18	47
Deactivation costs	7	5	2	3	1	4
Other non-recurring charges	168	160	20	768	13	59
Mark to market (MtM) losses on economic hedges	(61)	33	87	75	18	(59)
Adjusted EBITDA	**641**	**698**	**895**	**471**	**386**	**685**

Appendix:
Transformation Plan Reg. G Schedules

Reg. G: 2017 Guidance

Appendix Table A-1: 2017 Guidance

The following table summarizes the calculation of Free Cash Flow before Growth and provides a reconciliation to Adjusted EBITDA

($ millions)	Previous Guidance	Revised Guidance	Pro Forma for Transformation Plan
Adjusted EBITDA	**$2,700 - $2,900**	**$2,565 - $2,765**	**$1,745 - $1,945**
Interest payments	(1,065)	(825)	(355)
Income tax	(40)	(40)	(40)
Working capital / other	(240)	60	(45)
Adjusted Cash Flow from Operations	**$1,355 - $1,555**	**$1,760 - $1,960**	**$1,305 - $1,505**
Maintenance capital expenditures, net	(280) - (310)	(210) - (240)	(110) – (140)
Environmental capital expenditures, net	(40) - (60)	(25) - (45)	(25) - (45)
Distributions to non-controlling interests[1]	(185) – (205)	(185) – (205)	--
Consolidated Free Cash Flow before Growth	**$800 - $1,000**	**$1,290 - $1,490**	**$1,130 - $1,330**
Less: FCFbG at Non-Guarantor Subsidiaries[2]	(100)	(420)	--
NRG-Level Free Cash Flow before Growth	**$700 - $900**	**$870 - $1,070**	**$1,130 - $1,330**

[1] Includes NRG Yield distributions to public shareholders, and Capistrano and Solar distributions to non-controlling interests; [2] Reflects impact from NRG Yield and other excluded project subsidiaries

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Appendix Table A-2: Adjusted EBITDA Guidance Reconciliation: The following table summarizes the calculation of Adjusted EBITDA providing reconciliation to net income:

	2017 Adjusted EBITDA Previous Guidance		2017 Adjusted EBITDA Revised Guidance		Pro Forma for Transformation Plan	
($ millions)	**Low**	**High**	**Low**	**High**	**Low**	**High**
GAAP Net Income [1]	150	350	360	560	790	990
Income tax	80	80	80	80	60	60
Interest Expense and Debt Extinguishment Costs	1,065	1,065	825	825	355	355
Depreciation, Amortization, Contract Amortization and ARO Expense	1,235	1,235	1,150	1,150	440	440
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	110	110	110	110	60	60
Other Costs [2]	60	60	40	40	40	40
Adjusted EBITDA	**$2,700**	**$2,900**	**$2,565**	**$2,765**	**$1,745**	**$1,945**

[1] For purposes of guidance, fair value accounting related to derivatives are assumed to be zero; [2] Includes deactivation costs, gain on sale of businesses, asset write-offs, impairments and eVgo California settlement

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Appendix Table A-3: Adjusted EBITDA and FCFbG Guidance Reconciliation for Asset Sales: The following table summarizes the calculation of Adjusted EBITDA providing reconciliation to net income:

($ millions)	Asset to be Divested
Net (loss)/income	**240**
Plus:	
Income tax	20
Interest expense, net	400
Depreciation, Amortization, Contract Amortization, and ARO Expense	710
EBITDA	**1,370**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	70
Adjusted EBITDA	**1,440**
Interest payments	(380)
Collateral / working capital / other	(70)
Cash Flow from Operations	**990**
Maintenance capital expenditures, net	(50)
Distributions to non-controlling interests	(195)
Free Cash Flow before Growth - Consolidated	**745**
Less: Cash distributions to NRG (e.g. FCFbG at NRG-Level)	(325)
Free Cash Flow before Growth - Residual	**420**

[1] For purposes of guidance, fair value accounting related to derivatives are assumed to be zero; [2] Includes deactivation costs, gain on sale of businesses, asset write-offs, impairments and eVgo California settlement

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EBITDA and Adjusted EBITDA are non-GAAP financial measures. These measurements are not recognized in accordance with GAAP and should not be viewed as an alternative to GAAP measures of performance. The presentation of Adjusted EBITDA should not be construed as an inference that NRG’s future results will be unaffected by unusual or non-recurring items.

EBITDA represents net income before interest (including loss on debt extinguishment), taxes, depreciation and amortization. EBITDA is presented because NRG considers it an important supplemental measure of its performance and believes debt-holders frequently use EBITDA to analyze operating performance and debt service capacity. EBITDA has limitations as an analytical tool, and you should not consider it in isolation, or as a substitute for analysis of our operating results as reported under GAAP. Some of these limitations are:

EBITDA does not reflect cash expenditures, or future requirements for capital expenditures, or contractual commitments;

EBITDA does not reflect changes in, or cash requirements for, working capital needs;

EBITDA does not reflect the significant interest expense, or the cash requirements necessary to service interest or principal payments, on debt or cash income tax payments;

Although depreciation and amortization are non-cash charges, the assets being depreciated and amortized will often have to be replaced in the future, and EBITDA does not reflect any cash requirements for such replacements; and

Other companies in this industry may calculate EBITDA differently than NRG does, limiting its usefulness as a comparative measure.

Because of these limitations, EBITDA should not be considered as a measure of discretionary cash available to use to invest in the growth of NRG’s business. NRG compensates for these limitations by relying primarily on our GAAP results and using EBITDA and Adjusted EBITDA only supplementally. See the statements of cash flow included in the financial statements that are a part of this news release.

Adjusted EBITDA is presented as a further supplemental measure of operating performance. As NRG defines it, Adjusted EBITDA represents EBITDA excluding impairment losses, gains or losses on sales, dispositions or retirements of assets, any mark-to-market gains or losses from accounting for derivatives, adjustments to exclude the Adjusted EBITDA related to the non-controlling interest, gains or losses on the repurchase, modification or extinguishment of debt, the impact of restructuring and any extraordinary, unusual or non-recurring items plus adjustments to reflect the Adjusted EBITDA from our unconsolidated investments. The reader is encouraged to evaluate each adjustment and the reasons NRG considers it appropriate for supplemental analysis. As an analytical tool, Adjusted EBITDA is subject to all of the limitations applicable to EBITDA. In addition, in evaluating Adjusted EBITDA, the reader should be aware that in the future NRG may incur expenses similar to the adjustments in this news release.

Management believes Adjusted EBITDA is useful to investors and other users of NRG's financial statements in evaluating its operating performance because it provides an additional tool to compare business performance across companies and across periods and adjusts for items that we do not consider indicative of NRG’s future operating performance. This measure is widely used by debt-holders to analyze operating performance and debt service capacity and by equity investors to measure our operating performance without regard to items such as interest expense, taxes, depreciation and amortization, which can vary substantially from company to company depending upon accounting methods and book value of assets, capital structure and the method by which assets were acquired. Management uses Adjusted EBITDA as a measure of operating performance to assist in comparing performance from period to period on a consistent basis and to readily view operating trends, as a measure for planning and forecasting overall expectations, and for evaluating actual results against such expectations, and in communications with NRG's Board of Directors, shareholders, creditors, analysts and investors concerning its financial performance.

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Adjusted cash flow from operating activities is a non-GAAP measure NRG provides to show cash from operations with the reclassification of net payments of derivative contracts acquired in business combinations from financing to operating cash flow, as well as the add back of merger, integration and related restructuring costs. The Company provides the reader with this alternative view of operating cash flow because the cash settlement of these derivative contracts materially impact operating revenues and cost of sales, while GAAP requires NRG to treat them as if there was a financing activity associated with the contracts as of the acquisition dates. The Company adds back merger, integration related restructuring costs as they are one time and unique in nature and do not reflect ongoing cash from operations and they are fully disclosed to investors.

Free cash flow (before Growth investments) is adjusted cash flow from operations less maintenance and environmental capital expenditures, net of funding, preferred stock dividends and distributions to non-controlling interests and is used by NRG predominantly as a forecasting tool to estimate cash available for debt reduction and other capital allocation alternatives. The reader is encouraged to evaluate each of these adjustments and the reasons NRG considers them appropriate for supplemental analysis. Because we have mandatory debt service requirements (and other non-discretionary expenditures) investors should not rely on free cash flow before Growth investments as a measure of cash available for discretionary expenditures.

Free Cash Flow before Growth Investment is utilized by Management in making decisions regarding the allocation of capital. Free Cash Flow before Growth Investment is presented because the Company believes it is a useful tool for assessing the financial performance in the current period. In addition, NRG’s peers evaluate cash available for allocation in a similar manner and accordingly, it is a meaningful indicator for investors to benchmark NRG's performance against its peers. Free Cash Flow before Growth Investment is a performance measure and is not intended to represent net income (loss), cash from operations (the most directly comparable U.S. GAAP measure), or liquidity and is not necessarily comparable to similarly titled measures reported by other companies.