NRG Energy Inc.

Third Quarter 2018 Earnings Presentation

November 8, 2018

Safe Harbor

Forward-Looking Statements

In addition to historical information, the information presented in this presentation 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, 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, cyberterrorism and inadequate cybersecurity, 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 GenOn's emergence from bankruptcy, 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, 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, free cash flow guidance and excess cash guidance are estimates as of November 8, 2018. 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

Key Messages

Integrated Platform Produces Predictable Earnings: Narrowing 2018 guidance to upper-half of range and initiating strong 2019 financial guidance

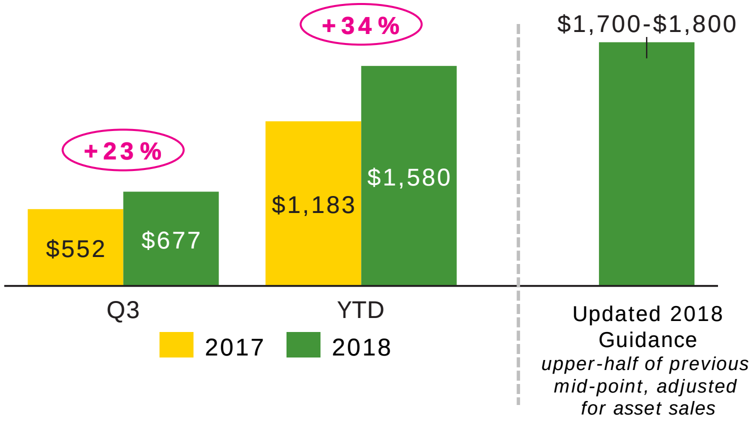
Transformation Plan On Track: Closed NRG Yield and Renewables sale; continued focus on execution with pivot to 2019 margin enhancement

Disciplined Capital Allocation: Announcing incremental $500 MM share repurchase program and affirming expected completion of first $1 Bn program by year-end

Q3 Business Update

Highlights and Updated 2018 Guidance

Adjusted EBITDA ($ MM)



- ☑ Strong Q3 results despite increased price volatility in ERCOT; strong operational and financial performance
- ☑ Current $1 Bn share repurchase program to be completed by year-end; announcing an incremental $500 MM program to be executed into 2019
- ☑ Removed ~$10 Bn of debt, including corporate debt of $640 MM in 4Q18

Initiating 2019 Guidance

($ millions)	**2019E Guidance**
Adjusted EBITDA	**$1,850 - $2,050**
Free Cash Flow Before Growth	**$1,250 - $1,450**
Excess Cash for Allocation	**~$2.6 Bn**

Guidance Exceeds Transformation Plan Pro Forma

Q3 and YTD Results 23% and 34% Higher Year-on-Year from Integrated Platform; Introducing Strong 2019 Guidance

Transformation Plan Update

Continued Progress on Plan Initiatives

1. Cost Savings and Margin Enhancement:

- ☑ $150 MM of cost savings in Q3; $375 MM YTD
- ☑ On track with margin enhancement; $6 MM YTD
- ☑ 92% of working capital target achieved through Q3

2. Portfolio Optimization:

- ☑ **Update:** Narrowing asset sale expectations and proceeds (to $3.1 Bn, from up to $3.2 Bn) for asset sales with line-of-sight to close
- ☑ Remaining 2018-2019 asset sales:
  - ☑ **Update:** NYLD/Renewables: $1,348 MM closed 3Q18
  - ☐ South Central: $1,000 MM targeted close by YE'18
  - ☐ Carlsbad: $365 MM COD 4Q18 and targeted close in 1Q19
  - ☐ Agua Caliente: ~$120 MM targeted to close in 1Q19

3. Capital Allocation:

- ☑ On track to achieve and maintain 3.0x Net Debt / Adj. EBITDA in 2018

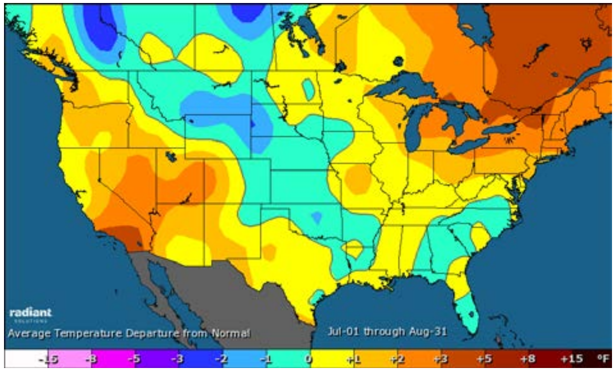
2018 Score Card as of 9/30/2018

($ millions)	YTD Realized	YTD % Achieved	2018 Target	2019 Target
Accretive & Recurring:				
Cost Savings	375	*75%*	500	590
Margin Enhancement	6	*20%*	30	135
Total EBITDA - Accretion	**$381**	***72%***	**$530**	**$725**
Maintenance Capex	24	*80%*	30	50
Total Recurring FCFbG - Accretion	**$405**	***72%***	**$560**	**$775**
Non-Recurring:				
Working Capital Improvement	92	*92%*	100	49
Cost to Achieve Total Transformation Plan	(114)	-	(162)	(84)
Total Non-Recurring	**($22)**	**-**	**($62)**	**($35)**
Annual Cash Accretion	**$383**	***77%***	**$498**	**$740**
Cumulative Cash Accretion *(Incremental Capital Available for Allocation)*	**~$710**	***~86%***	**~$825**	**$1,565**

On Track to Achieve Transformation Plan Targets

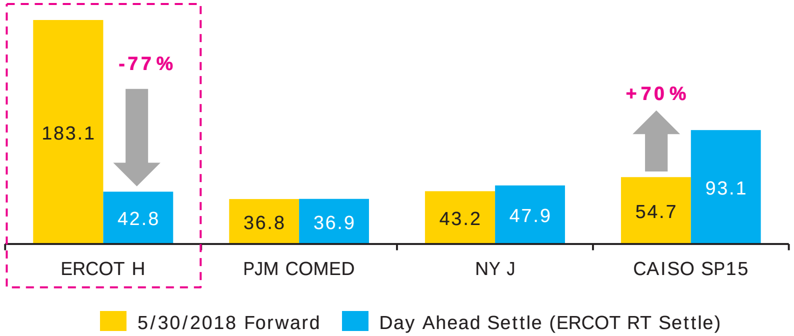
Summer 2018 Review

Mixed Weather during July-August…



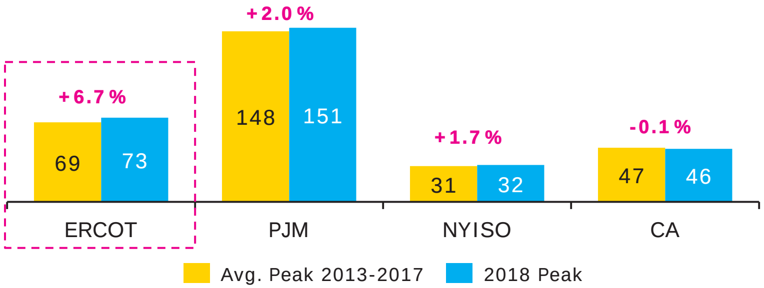
…Leads to Volatile Summer Prices Particularly in ERCOT and CA

On-Peak Prices ($/MWh)[2]



Peak Demand Grows in Texas and East

Peak Demand (GW)[1]



Summer 2018 Highlights

- ERCOT experienced significant price volatility
  - Actual prices 77% below expectations
  - Robust load growth offset by near-perfect performance by generators
- Significant uplift in CA power prices as a result of strong regional natural gas prices

ERCOT Prices Lower than Forwards due to Near Perfect Generator Performance; Peak Load Growth Remains Strong in ERCOT

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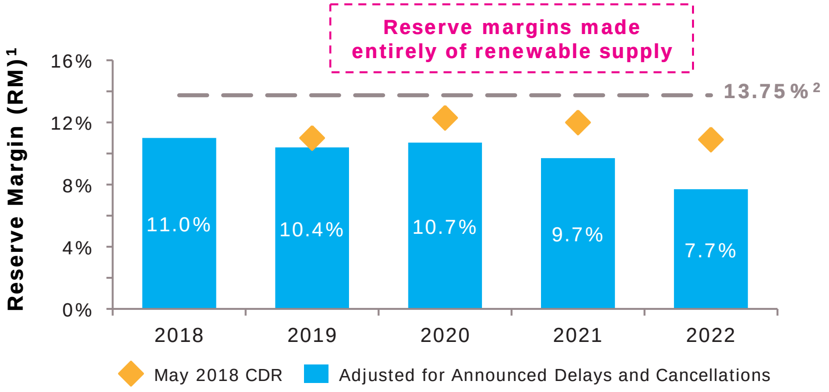
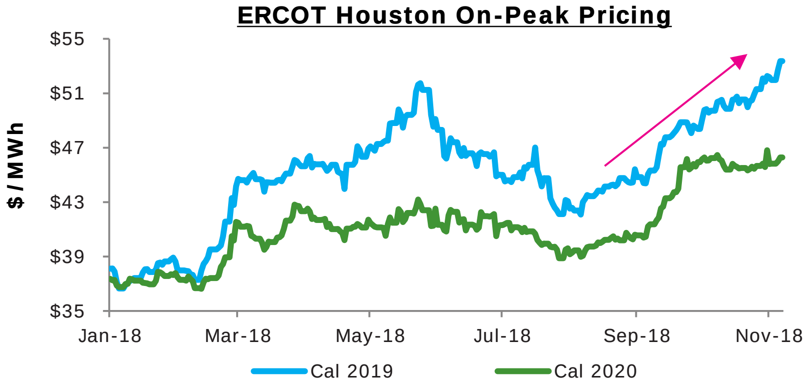
[1] Sources: ERCOT, PJM ISO, NYISO, CAISO data; [2] Sources: ICE, ERCOT, PJM ISO, NYISO, CAISO data; July-August on-peak prices

Market Outlook

ERCOT: Tightening Reserve Margins Leading to Increased Power Prices





East: Regulatory Changes to Improve Capacity and Energy Markets

❑ **PJM Capacity Market Reforms:**

- Strong MOPR continues to be the most compelling option, reflecting the true cost of generation
- All carve-out proposals fail to "protect the integrity of competition in the wholesale capacity market" as FERC requires
- Implementation prior to next capacity auction, which has been delayed until August 2019

❑ **PJM Energy Market Reforms:**

- Expect FERC order on fast-start pricing soon
- ORDC moving through stakeholder process

❑ **ISO-NE Fuel Security:**

- New England's winter reliability continues to be at risk due to expiration of its winter reliability program (fuel security)
- Key driver of the next capacity auction (FCA #13) will be whether FERC requires Mystic to be priced in the auction

Strong ERCOT Fundamentals and Improving Regulatory Outlook in the East

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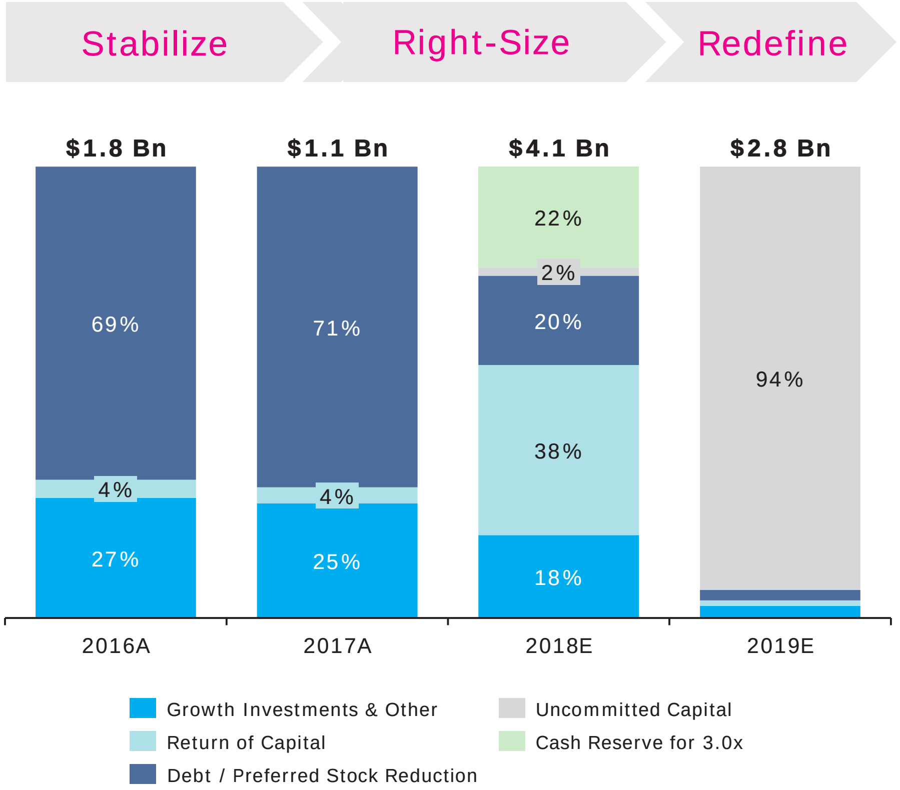
[1] Source: ERCOT; 2018 Reserve Margin based on ERCOT News Release dated 4/30/2018; Adjusted for announced delays and cancellations excludes Bethel CAES, Indeck Wharton, and Pinecrest Energy Center due to project cancellations; excludes Oklaunion beginning in 2021 due to retirement announcement, delays Halyard Wharton and Halyard Henderson by one year each due to notification of delay; [2] Prior target Reserve Margin

Disciplined Capital Allocation

Capital Allocation Mix



Capital Allocation Priorities

Achieve and maintain
3.0x Net Debt / Adjusted EBITDA

Excess after **3.0x** achieved, reinvest at or above hurdle rate of **12-15%** unlevered pretax return with **5-year** or less payback

Growth Investments	**Return of Capital**
Consistent with strategy	Compelling at current price
Superior to implied share price return	Value accretive

Completing 2018 Capital Allocation with Incremental Share Repurchase Program;
To Address 2019 Capital Allocation on 4Q18 Earnings Call

Financial Update

2018 YTD Financial Summary

($ millions)	**9/30/2018**	
	Three Months Ended	**Nine Months Ended**
Generation[1]	$408	$825
Retail	269	755
Adjusted EBITDA	**$677**	**$1,580**
Free Cash Flow before Growth (FCFbG)	**$556**	**$856**

Results:

- Excludes NRG Yield and Renewables
- Still includes South Central, Agua Caliente

- Closed on sale of NRG's interest in NRG Yield and the Renewables platform
  - Results treated as discontinued operations effective January 1, 2018
  - Reduced debt from ~$17 Bn at beginning of year to ~$6.5 Bn[2]
- $640 MM of targeted debt reduction completed
  - $485 MM – balance of 2022 senior notes (nearest maturity)
  - $155 MM – term loan redemptions
  - On track to achieve and maintain 3.0x Net Debt / Adjusted EBITDA
- Fully funded ASR[3] under way to complete second phase of $1 Bn share repurchase program
- Announcing new authorization for an additional $500 MM of share repurchases to be executed into 2019

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[1] Includes Corporate segment; [2] Includes corporate debt reduction of $640 MM completed in 4Q18; excludes MWG, Agua and other non-recourse debt; [3] Accelerated Share Repurchases

Updating 2018 Financial Guidance

($ millions)	Previous Guidance	Full Year Effect of 2018 Asset Sales[2]	Previous Guidance Adjusted for 2018 Asset Sales	Updated and Narrowed Guidance
Generation & Renewables[1]	$950 – $1,050	(255)	$695 – $795	$775 – $825
Retail	900 – 1,000	-	900 – 1,000	925 – 975
NRG Yield	950	(950)	-	-
Adjusted EBITDA	**$2,800 – $3,000**	**(1,205)**	**$1,595 – $1,795**	**$1,700 – $1,800**
Consolidated FCFbG	**$1,550 – $1,750**	**(590)**	**$960 – $1,160**	**$1,050 – $1,150**

- Updating the previous guidance for the announced asset sales
  - NRG Yield and Renewables platform treated as discontinued operations for full year 2018
  - Sale of South Central expected to close in 4Q18 and treated as discontinued operations for 2018 guidance
- Updated 2018 Guidance includes:
  - ~$120 MM of Generation EBITDA from BETM (sold in 2018) and Agua Caliente (to be sold in 2019)
  - ~$25 MM of Retail EBITDA for partial year effect of XOOM (~$45 MM in 2019)

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[1] Includes Corporate Segment; [2] Includes NRG Yield, Renewables, South Central and Boston Energy Trading and Marketing (BETM)

Introducing 2019 Guidance

($ millions)	**2019 Guidance**
Generation[1]	$850 – $950
Retail	1,000 – 1,100
Adjusted EBITDA	**$1,850 - $2,050**
Free Cash Flow before Growth	**$1,250 - $1,450**

2018 Pro Forma Adjusted EBITDA mid-point ***(see slide 11 of 2Q18 earnings deck)***	**$1,600**
Add: Incremental cost savings and margin enhancement	195
Add: Change in curves/(supply costs)	~150
2019 Guidance (Mid-Point)	**$1,950**

2019 Guidance Reflects:

- Sale of remaining interest in Agua Caliente
- Full year impact of XOOM (~$45 MM)
- Transformation Plan in-line with targets:
  - $90 MM incremental costs savings vs 2018 (Total 2019/2020 = $590 MM)
  - $105 MM incremental margin enhancement vs 2018 (Total 2019 = $135 MM; 2020 expected to be $215 MM)

Guidance Exceeds Transformation Plan Pro Forma; Benefiting from Improved Forward Curves

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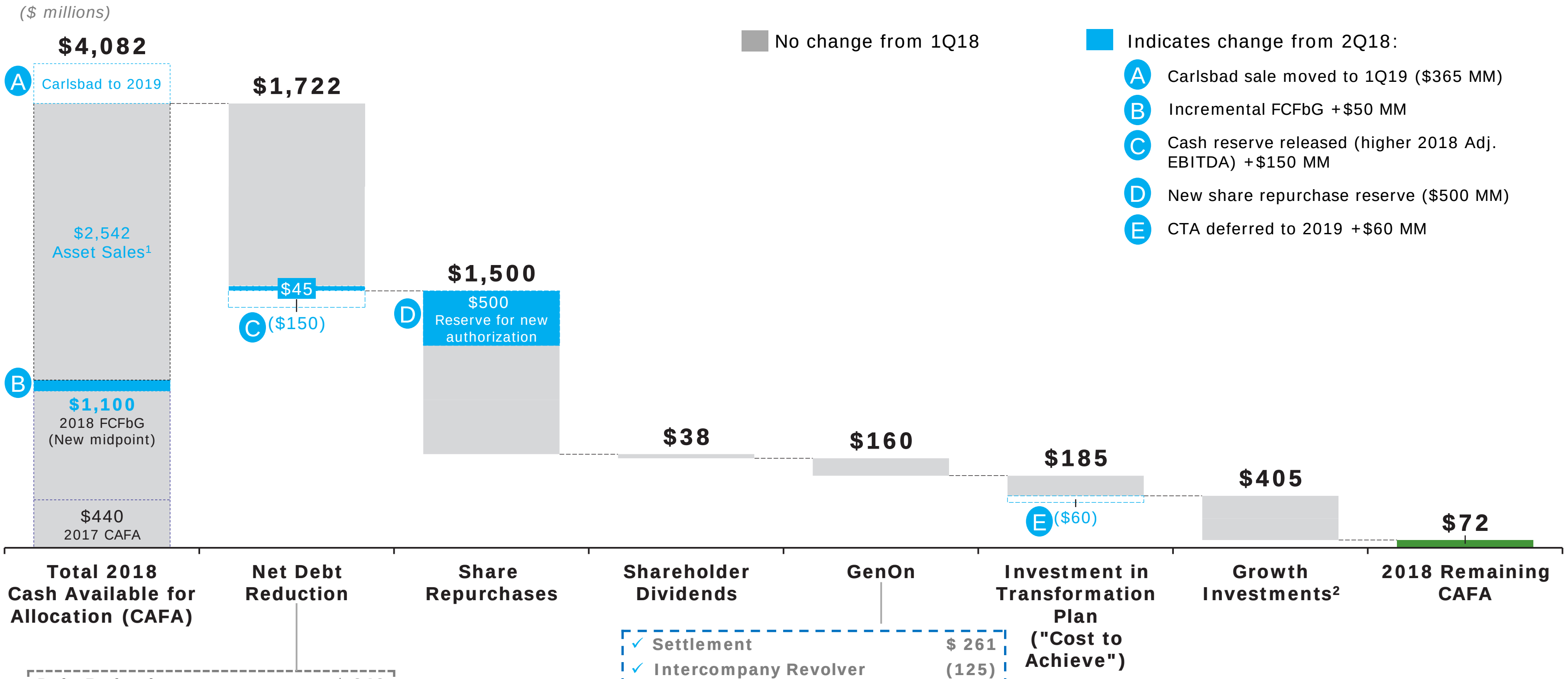
[1] Includes Corporate Segment

2018 Capital Allocation



Indicates change from 2Q18:

- Ⓐ Carlsbad sale moved to 1Q19 ($365 MM)
- Ⓑ Incremental FCFbG +$50 MM
- Ⓒ Cash reserve released (higher 2018 Adj. EBITDA) +$150 MM
- Ⓓ New share repurchase reserve ($500 MM)
- Ⓔ CTA deferred to 2019 +$60 MM

Debt Reduction	$ 640
Term Loan Amortization	19
Midwest Gen Debt Amortization³	103
Debt Premiums and Refinancing Fees	**45**
Cash Reserve to Achieve 3.0x	**915**

✓ Settlement	$ 261
✓ Intercompany Revolver	(125)
✓ Other Settlement Credits	28
Pension	14
✓ Interest on Intercompany Revolver	(12)
✓ Other Balances due to NRG	(6)

✓ Settled as part of July payment

2018 Capital Now Fully Allocated

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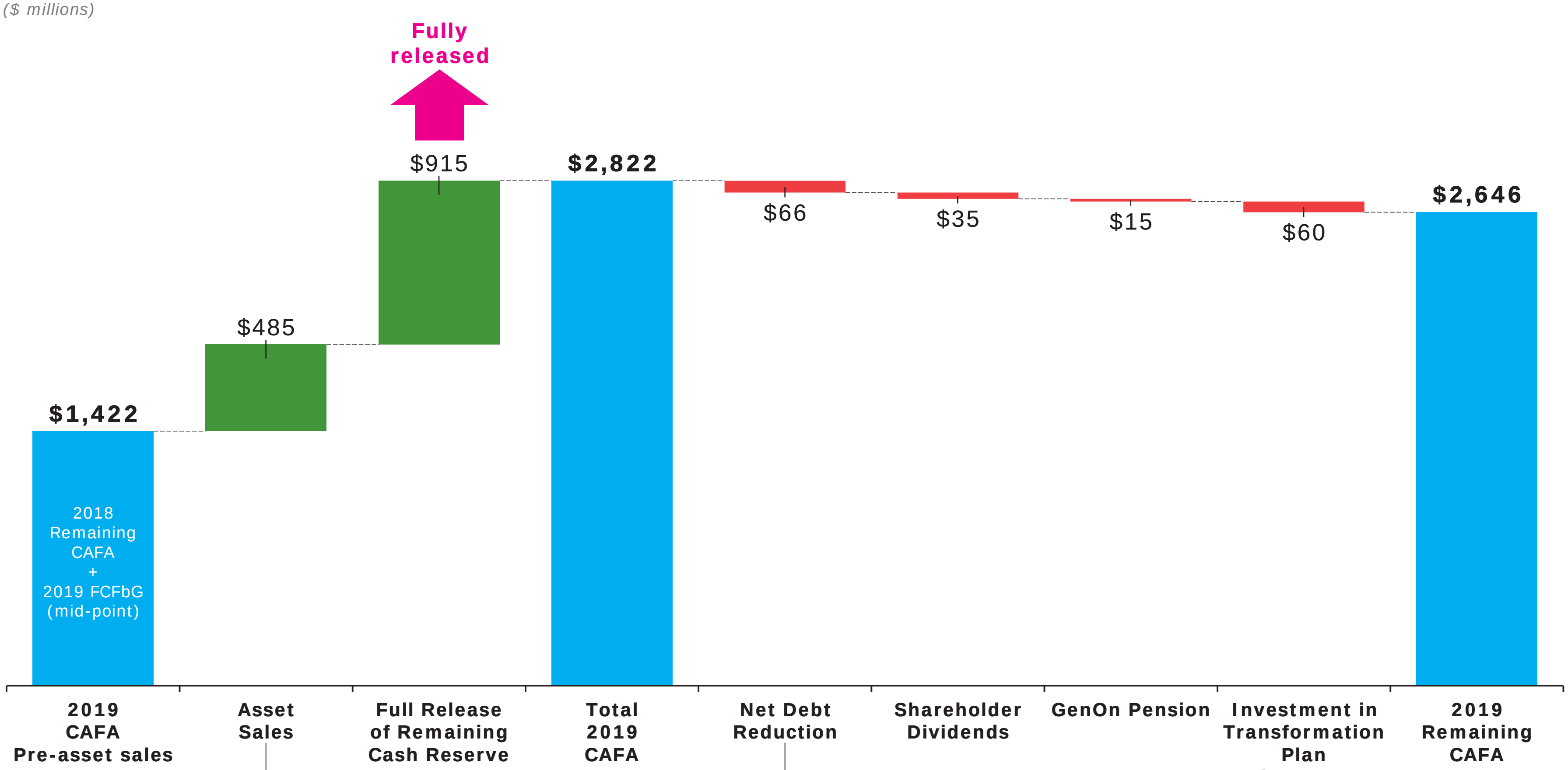
¹ See appendix slide 38 for list of announced asset sales; includes transaction fees of $60 MM; ² Net of financing; ³ $103 MM of 2018 capacity revenue sold forward in 2016; 2018 payment to counterparty treated as debt amortization for accounting purposes

2019 Excess Capital Update



Carlsbad	$365
Agua Caliente	120

Term Loan Amortization	$ 17
Midwest Gen Debt Amortization[1]	49

Continue to Expect >$2.6 Bn of Excess Capital in 2019

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[1] $49 MM of 2019 capacity revenue sold forward in 2016; 2019 payment to counterparty treated as debt amortization for accounting purposes

Corporate Credit Profile

$ millions	2018 Pro Forma Guidance	2019 Guidance
Corporate Debt	**$7,169[1]**	**$6,524[1]**
2018 Term Loan Amortization	(5)	(17)
Debt Reduction completed in 4Q18	(640)	-
Pro Forma Corporate Debt	**$6,524**	**$6,507**
Cash & Cash Equivalents @ NRG-Level/Min Cash	(500)	(500)
Cash Reserve to meet 3.0x target	(915)	-
Pro Forma Corporate Net Debt	**~$5,110**	**~$6,000**
Adj. EBITDA	**$1,650[2]**	**$1,950**
Less: MWG Adj. EBITDA, net of cash distributions	(80)	(30)
Other Adjustments[3]	150	150
Corporate Adj. EBITDA	**$1,720**	**$2,070**
Corporate Net Debt / Corporate Adj. EBITDA	**3.0x**	**<3.0x**
Adj. CFO[4] / Corporate Net Debt	**25.2%**	**25.1%**
(Corporate Adj. CFO + Corporate Interest[5]) / Corporate Interest	**4.2x**	**5.3x**

Credit Metrics Significantly Better than Current BB/Ba3 Credit Rating

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[1] 2018 reflects balance at 9/30/2018 (includes NRG Energy, Inc. term loan facility, senior notes, revolver, capital leases and tax exempt bonds); [2] Midpoint guidance adjusted to pro forma for ~$20 MM incremental 2018 full year effect for XOOM less non-recurring ~$120 MM adjustment for asset divestitures; [3] Reflects non-cash expenses (i.e. nuclear amortization, equity compensation amortization, and bad debt expense) that are included in Adjusted EBITDA; [4] See slide 42 for details; [5] 2018 excludes interest payments of ~$45 MM related to Ivanpah and Agua Caliente

Closing Remarks

2018 Priorities

☐ **Deliver on Financial and Operational Objectives**

- ☑ Narrowed full year financial guidance
- ☑ Strong year-to-date financial, operational and safety performance
- ☑ $640 MM in corporate debt reduction
- ☑ $1 Bn share repurchase program by year-end
- ☐ Incremental $500 MM share repurchase program into 2019

☐ **Execute on NRG Transformation Plan Objectives**

- ☐ $500 MM of EBITDA-accretive cost savings in 2018
- ☐ $30 MM of EBITDA-accretive margin enhancement in 2018
- ☐ Achieve 3.0x Net Debt / Adjusted EBITDA by end of 2018

☐ **Complete Asset Sales, Dispositions, and Acquisitions**

- ☑ Closed drop down of Buckthorn Solar to NRG Yield
- ☑ Closed on acquisition of XOOM Energy
- ☑ Closed on sale of BETM, Canal 3 and Spanish Town
- ☑ Closed on sales of Keystone and Conemaugh
- ☑ Closed on sale of NRG Yield / Renewables
- ☐ South Central targeted to close by year-end 2018
- ☐ Carlsbad expected COD 4Q18; targeted to close sale in 1Q19
- ☐ Expect GenOn to exit Bankruptcy by year-end 2018

☑ **Provided Long-Term Strategy at March 27, 2018 Analyst Day**

Appendix

Transformation Plan Score Card

2018 Progress as of 9/30/2018

($ millions)	YTD Realized	YTD % Achieved	2018 Target
Accretive & Recurring:			
Cost Savings	375	*75%*	500
Margin Enhancement	6	*20%*	30
Total EBITDA - Accretion	**$381**	***72%***	**$530**
Maintenance Capex	24	*80%*	30
Total Recurring FCFbG - Accretion	**$405**	***72%***	**$560**
Non-Recurring:			
Working Capital Improvement	92	*92%*	100
Cost to Achieve Total Transformation Plan	(114)	-	(162)
Total Non-Recurring	**($22)**	**-**	**($62)**
Annual Cash Accretion	**$383**	***77%***	**$498**
Cumulative Cash Accretion *(Incremental Capital Available for Allocation)*	**~$710**	***~86%***	**~$825**

Transformation Plan Targets

($ millions)	2017	2017 Realized	2018	2019	2020 / Run Rate
Accretive & Recurring:					
Cost Savings	65	150	500	590	590
Margin Enhancement*	0	-	30	135	215
Total EBITDA -Accretion	**$65**	**$150**	**$530**	**$725**	**$805**
Maintenance Capex*	0	-	30	50	50
Total Recurring FCFbG Accretion	**$65**	**$150**	**$560**	**$775**	**$855**
Non-Recurring:[1]					
Working Capital Improvement	175	221	100	49	--
Cost to Achieve Total Transformation Plan	(115)	(44)	(162)	(84)	--
Total Non-Recurring	**$60**	**$177**	**($62)**	**($35)**	**--**
Annual Cash Accretion	**$125**	**$327**	**$498**	**$740**	**$855**
Cumulative Cash Accretion *(Incremental Capital Available for Allocation)*	**$125**	**~$327**	**$825**	**$1,565**	**$2,420**

* **On track:** no stated target in 2017 per plan announced 7/12/2017

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[1] 2018 Cost to Achieve target and 2019 working capital improvement target updated from original targets due to shifting of targets in forward years due to achievement levels in 2017; total targets did not change

Appendix: Operations

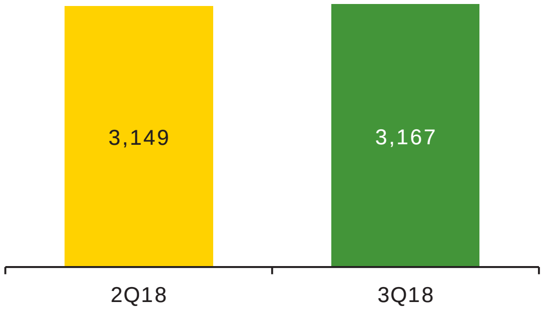
Retail: Operational Metrics

Q3 Highlights

- Delivered $269 MM in adjusted EBITDA, overcoming materially higher supply costs than 3Q17
- Continued momentum of profitable count growth and volume growth
- Deepened innovative solution offering via partnership agreement with Google

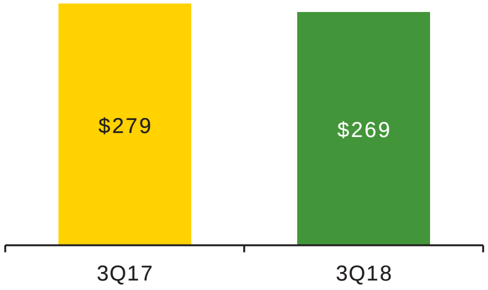
Growth in Q3 Mass Customer Count

Mass Recurring Customers[1] (000s)



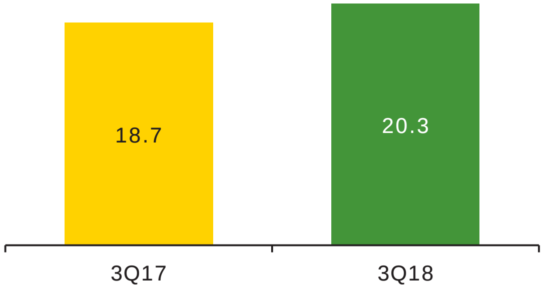
Strong Q3 EBITDA Earnings

Adjusted EBITDA ($ millions)



Higher Q3 Volumes

Delivered TWh

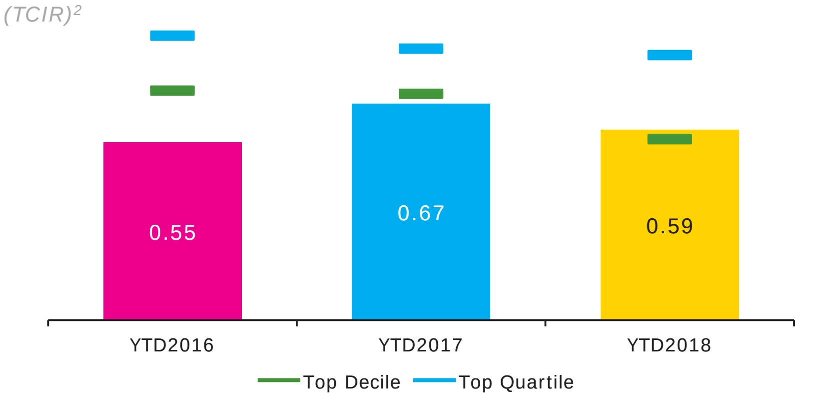


On Track for Another Year of Record Earnings in Retail

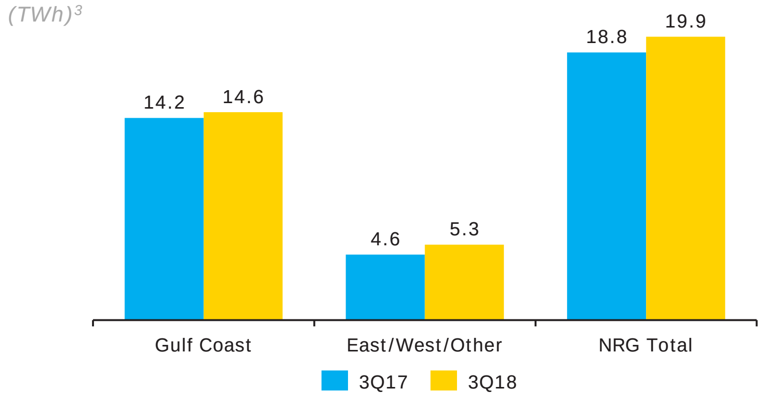
[1] Mass recurring customer count includes customers that subscribe to one or more recurring services, such as electricity and natural gas; excludes C&I customers

Generation: Operational Metrics

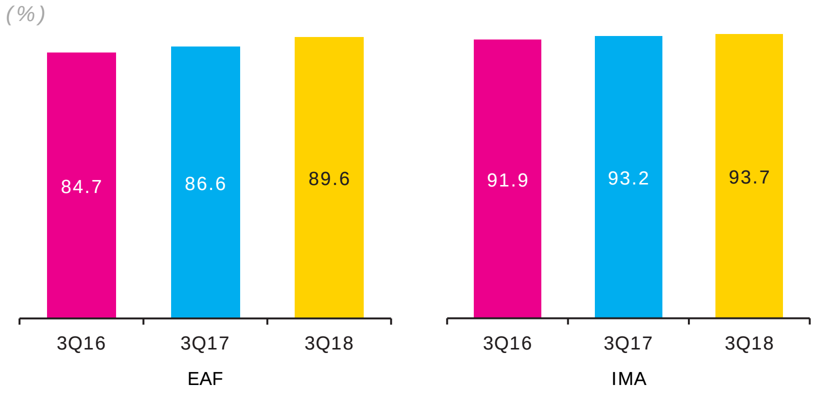
Safety[1]



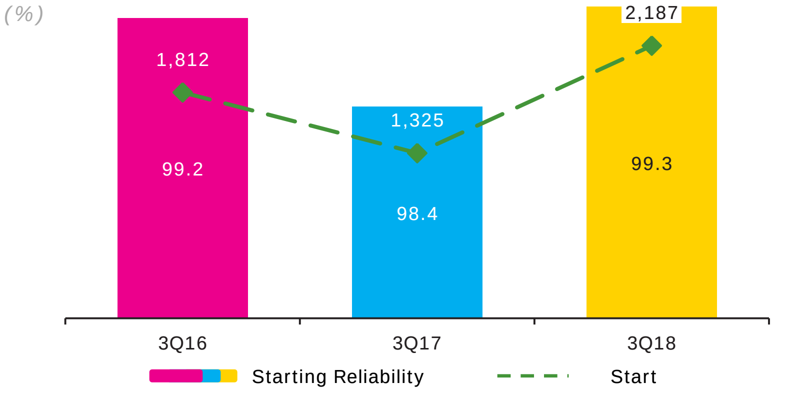
Production



Baseload Equivalent Availability Factor (EAF) and In-the-Money Availability (IMA)



Gas and Oil Starts and Reliability



Strong Summer Performance With Focus on Safety and Reliability

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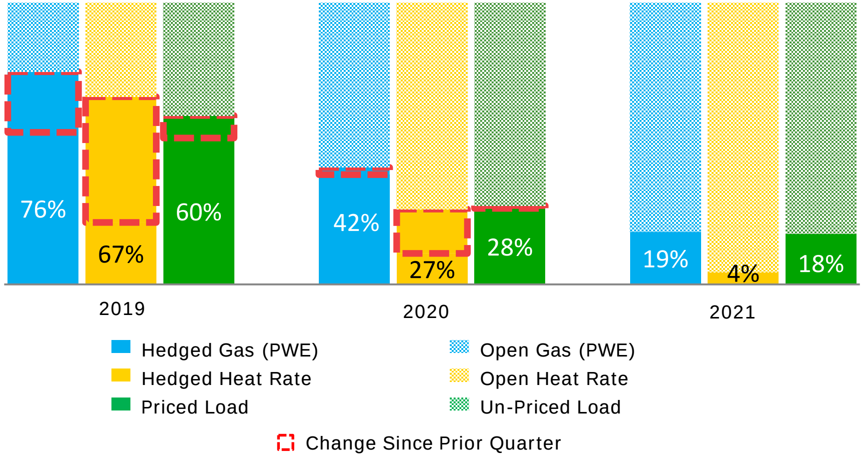
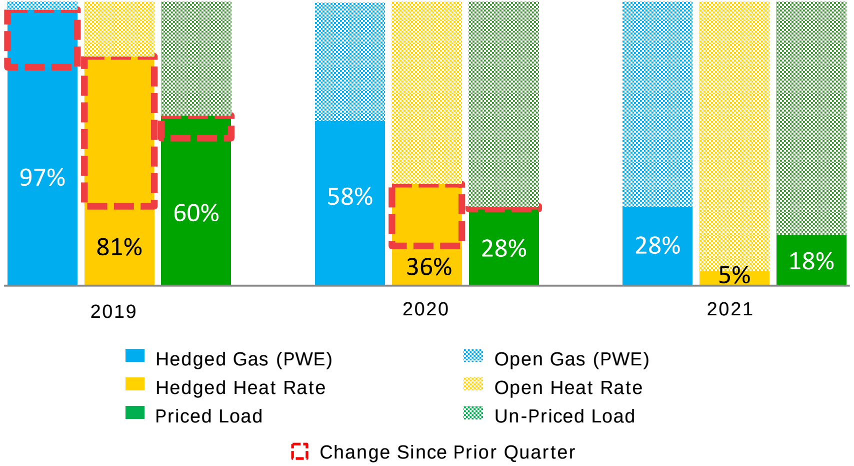
[1] Excludes Goal Zero, NRG Home Services and NRG Home Solar; 2018 top decile and top quartile based on Edison Electric Institute 2016 Total Company Survey results; 2016 and 2017 top decile and top quartile based on Edison Electric Institute 2015 Total Company Survey results; [2] TCIR = Total Case Incident 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

Pro Forma Portfolio[1]
Managing Commodity Price Risk

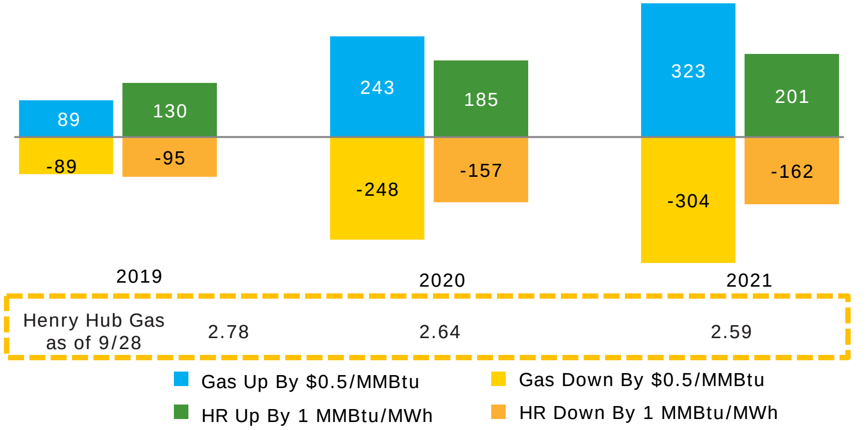
Total Portfolio Generation and Retail Hedge Position[1,2]



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

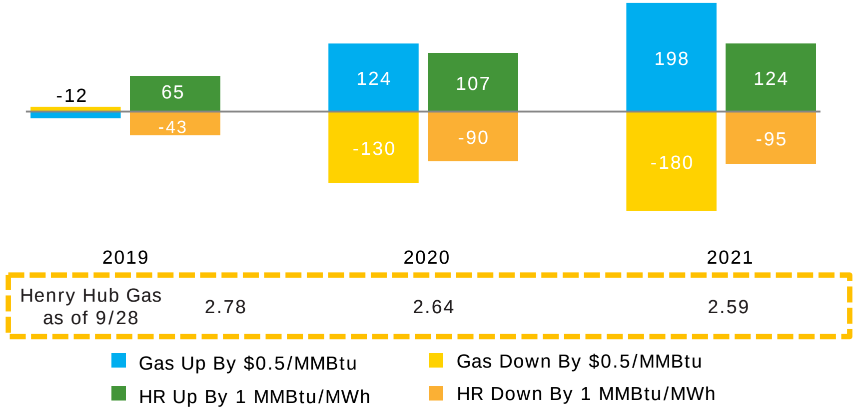


Total Portfolio Sensitivity to Gas Price and Heat Rate[1,3]



	2019	2020	2021
Henry Hub Gas as of 9/28	2.78	2.64	2.59

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



	2019	2020	2021
Henry Hub Gas as of 9/28	2.78	2.64	2.59

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[1] Portfolio as of 9/28/2018, includes TEXAS, PJM, NY, NE, CAISO & Cottonwood, excludes GenOn, MISO, Yield & Renew; [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 39% and 19% for 2019 and 2020, respectively

Hedge Disclosure: Coal and Nuclear Operations

	Coal & Nuclear Portfolio [1]	Texas			East		
		2019	2020	2021	2019	2020	2021
	Net Coal and Nuclear Capacity (MW)[2]	5,329	5,329	5,329	3,140	3,140	3,140
	Forecasted Coal and Nuclear Capacity (MW)[3]	4,029	3,975	3,761	1,030	743	326
	Total Coal and Nuclear Sales (GWh)[4]	34,267	20,702	8,716	8,847	3,475	1,202
	Percentage Coal and Nuclear Capacity Sold Forward[5]	97%	59%	26%	98%	53%	42%
	Total Forward Hedged Revenues[6]	$1,754	$736	$353	$262	$96	$33
	Weighted Average Hedged Price ($ per MWh)[6]	$51.18	$35.57	$40.55	$29.63	$27.77	$27.39
	Average Equivalent Natural Gas Price ($ per MMBtu)[6]	$2.65	$2.52	$2.64	$2.73	$2.63	$2.64
Gross Margin Sensitivities $ in MM	Gas Price Sensitivity Up $0.50/MMBtu on Coal and Nuclear Units	($75)	$47	$125	$63	$77	$73
	Gas Price Sensitivity Down $0.50/MMBtu on Coal and Nuclear Units	$38	($91)	($161)	($29)	($39)	($19)
	Heat Rate Sensitivity Up 1 MMBtu/MWh on Coal and Nuclear Units	$31	$65	$90	$34	$41	$34
	Heat Rate Sensitivity Down 1 MMBtu/MWh on Coal and Nuclear Units	($23)	($57)	($81)	($20)	($33)	($14)

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[1] Portfolio as of 9/28/2018. Includes TEXAS and PJM; Excludes MISO.

[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 9/28/2018 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 9/28/2018 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 2017 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 forward power and natural gas equivalent coal and nuclear sales

Commodity Prices

Forward Prices[1]	2018	2019	2020	Annual Average for 2018-2020
NG Henry Hub ($/MMBtu)	$2.78	$2.64	$2.59	$2.67
PRB 8800 ($/Ton)	$12.40	$12.40	$12.35	$12.38
ERCOT Houston Onpeak ($/MWh)	$49.02	$45.88	$43.99	$46.30
ERCOT Houston Offpeak ($/MWh)	$23.30	$21.68	$20.90	$21.96
ERCOT Houston RTC ($/MWh)	$35.28	$33.01	$31.70	$33.33
PJM West Onpeak ($/MWh)	$38.91	$36.89	$34.90	$36.90
PJM West Offpeak ($/MWh)	$28.75	$26.83	$25.46	$27.01
PJM West RTC ($/MWh)	$33.48	$31.54	$29.87	$31.63

[1] Prices as of 9/28/2018

Fuel Statistics

	3Q		YTD	
Domestic[1]	**2018**	**2017**	**2018**	**2017**
Coal Consumed (mm Tons)	7.1	6.7	17.4	18.0
PRB Blend	**99%**	**92%**	**99%**	**93%**
East	96%	94%	96%	97%
Gulf Coast	100%	92%	100%	92%
Bituminous	**1%**	**1%**	**1%**	**1%**
East	4%	6%	4%	3%
Lignite	**0%**	**7%**	**0%**	**6%**
Gulf Coast	0%	8%	0%	8%
Cost of Coal ($/Ton)	**$ 33.45**	**$ 32.34**	**$ 32.67**	**$ 32.33**
Cost of Coal ($/MMBtu)	**$ 1.95**	**$ 1.90**	**$ 1.91**	**$ 1.90**
Cost of Gas ($/MMBtu)	**$ 3.43**	**$ 3.02**	**$ 3.08**	**$ 3.10**

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

Q3 2018 Generation & Operational Performance Metrics

	2018	**2017**			**2018**		**2017**	
(MWh 000's)	**Generation[1]**	**Generation[1]**	**MWh Change**	**% Change**	**EAF[2]**	**NCF[3]**	**EAF[2]**	**NCF[3]**
Gulf Coast	14,638	14,186	452	3%	90%	50%	93%	47%
East/West/Other	5,306	4,567	739	16%	90%	20%	89%	16%
Total	**19,944**	**18,753**	**1,191**	**6%**	**90%**	**36%**	**91%**	**33%**
Gulf Coast – Texas Nuclear	2,518	2,516	2	0%	100%	99%	100%	97%
Gulf Coast – Texas Coal	7,090	7,161	(70)	(1%)	91%	77%	90%	77%
Gulf Coast – South Central Coal	839	1,218	(379)	(31%)	83%	42%	89%	61%
East Coal	3,081	2,226	855	38%	86%	43%	76%	29%
Baseload	**13,528**	**13,121**	**408**	**3%**	**90%**	**65%**	**87%**	**62%**
Renewables	150	461	(311)	(68%)	100%	30%	99%	30%
Intermittent	**150**	**461**	**(311)**	**(68%)**	**100%**	**30%**	**99%**	**30%**
East Oil	236	130	105	81%	94%	3%	92%	2%
Gulf Coast – Texas Gas	2,088	1,813	275	15%	88%	22%	92%	19%
Gulf Coast – South Central Gas	2,101	1,478	624	42%	92%	36%	96%	25%
East Gas	901	534	367	69%	88%	16%	94%	9%
West Gas	938	1,215	(277)	(23%)	92%	24%	99%	31%
Intermediate / Peaking	**6,265**	**5,171**	**1,095**	**21%**	**91%**	**19%**	**94%**	**16%**

[1] Excludes line losses, station service and other items; [2] EAF – Equivalent Availability Factor; [3] NCF – Net Capacity Factor

YTD 2018 Generation & Operational Performance Metrics

(MWh 000's)	2018 Generation[1]	2017 Generation[1]	MWh Change	% Change	2018 EAF[2]	2018 NCF[3]	2017 EAF[2]	2017 NCF[3]
Gulf Coast	37,783	37,975	(192)	(1%)	86%	43%	88%	42%
East/West/Other	11,390	11,525	(135)	4%	86%	14%	86%	13%
Total	**49,173**	**49,500**	**(327)**	**(1%)**	**86%**	**30%**	**88%**	**29%**
Gulf Coast – Texas Nuclear	6,969	6,934	35	1%	94%	91%	92%	90%
Gulf Coast – Texas Coal	18,253	18,649	(396)	(2%)	86%	67%	91%	68%
Gulf Coast – South Central Coal	2,338	3,187	(848)	(27%)	77%	39%	79%	53%
East Coal	6,742	6,670	73	1%	81%	30%	82%	29%
Baseload	**34,303**	**35,439**	**(1,136)**	**(3%)**	**84%**	**55%**	**87%**	**56%**
Renewables	770	1,323	(552)	(42%)	100%	30%	99%	25%
Intermittent	**770**	**1,323**	**(552)**	**(42%)**	**100%**	**30%**	**99%**	**25%**
East Oil	469	217	252	116%	89%	2%	88%	1%
Gulf Coast – Texas Gas	3,778	3,717	61	2%	82%	13%	88%	13%
Gulf Coast – South Central Gas	6,445	5,489	956	17%	92%	37%	92%	31%
East Gas	1,354	1,047	307	29%	87%	8%	85%	6%
West Gas	2,055	2,268	(213)	(9%)	87%	18%	90%	19%
Intermediate / Peaking	**14,100**	**12,738**	**1,362**	**11%**	**87%**	**14%**	**88%**	**13%**

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[1] Excludes line losses, station service and other items; [2] EAF – Equivalent Availability Factor; [3] NCF – Net Capacity Factor

Capacity Clears: NRG Standalone

Capacity Revenue by Calendar Year[1] ($ MM)

Market	2018	2019	2020	2021
PJM	$310	$317	$282	299
NYISO	$133	$68	$19	$0
NEISO	$157	$149	$110	$90

NYISO 2018, 2019 & 2020 contains MWs that will be either bid into upcoming auctions or sold bilaterally

Market	Region	Planning Year	Average Price ($/kW-Month)	MWs Cleared	Estimated Qualified Capacity[2]
ISO-NE	Connecticut	2018-2019	$9.55	1,535	1,535
		2019-2020	$7.03	1,529	1,529
		2020-2021	$5.30	1,529	1,529
		2021-2022	$4.63	1,529	1,529
NYISO[3]		2018	$4.23	2,628	2,816
		2019	$3.18	1,790	2,800
		2020	$4.11	392	2,800
		2021	-	-	2,800

Assumptions:

- ISO-NE and NYISO data as of 9/28/2018

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[1] 2018 values exclude non-recurring CAISO payments; [2] Capacity that can be bid in a capacity auction; estimated as of 9/28/2018 and is subject to change; [3] NYISO - NYC estimated qualified capacity is 1.2 GW; NYISO - Central estimated qualified capacity is 1.6 GW

PJM Capacity Clears

Capacity Revenue by Calendar Year ($ MM)

Market	2018	2019	2020	2021
PJM	$310	$317	$282	$299

Capacity Revenue by Delivery Year ($ MM)

Market	18/19	19/20	20/21	21/22
PJM	$334	$305	$265	$322

			Base Product		Capacity Performance Product	
Market	**Region**	**Planning Year**	**Average Price ($/MW-Day)**	**MWs Cleared**	**Average Price ($/MW-Day)**	**MWs Cleared**
PJM	ComEd	2018-2019	$25.58	221	$215.00	3,509
		2019-2020	$182.77	65	$202.77	3,738
		2020-2021			$188.12	3,315
		2021-2022			$195.55	3,995
PJM	DPL South	2018-2019	$210.63	98	$217.08	481
		2019-2020	NA	NA	$119.77	481
		2020-2021			$187.87	519
		2021-2022			$165.73	552
PJM	PEPCO	2018-2019	NA	NA	$229.10	46
		2019-2020	NA	NA	$100.00	66
		2020-2021			$86.04	67
		2021-2022			$140.00	72
PJM	Net Total	2018-2019	$82.51	319	$220.21	4,035
		2019-2020	$182.77	65	$191.89	4,284
		2020-2021			$186.34	3,901
		2021-2022			$191.12	4,619

Assumptions:

- PJM Data as of 5/23/2018
- Pro forma for announced business and asset sales
- Represents merchant wholesale generation

PJM Asset List: Merchant Wholesale Generation

Net Generating Capacity by LDA[1]

ComEd (4,336 MW, Net)

Name	Location	Capacity	Entity	Ownership %
Fisk	Chicago, IL	172	NRG	100%
Joliet	Joliet, IL	1,326	NRG	100%
Powerton	Pekin, IL	1,538	NRG	100%
Waukegan	Waukegan, IL	790	NRG	100%
Will County	Romeoville, IL	510	NRG	100%

DPL (593 MW, Net)

Name	Location	Capacity	Entity	Ownership %
Indian River	Millsboro, DE	426	NRG	100%
Vienna	Vienna, MD	167	NRG	100%

PEPCO (78 MW, Net)

Name	Location	Capacity	Entity	Ownership %
NRG Chalk Point CT	Prince Georges County, MD	78	NRG	100%

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[1] Load Delivery Area

Appendix: Finance

Q3 2018 YTD Net Capital Expenditures

($ millions)	**Maintenance**	**Environmental**	**Growth[1]**	**Total**
Retail	$14	-	$45	$59
Generation				
Gulf Coast	93	-	-	93
East/West[2]	22	1	133	156
Corporate	6	-	31	37
Total Cash Capital Expenditures	**$135**	**1**	**$209**	**$345**
Other Investments[3]	-	-	232	232
Project Funding, net of fees[4]	-	-	(247)	(247)
Total Capital Expenditures and Growth Investments, net	**$135**	**1**	**$194**	**$330**

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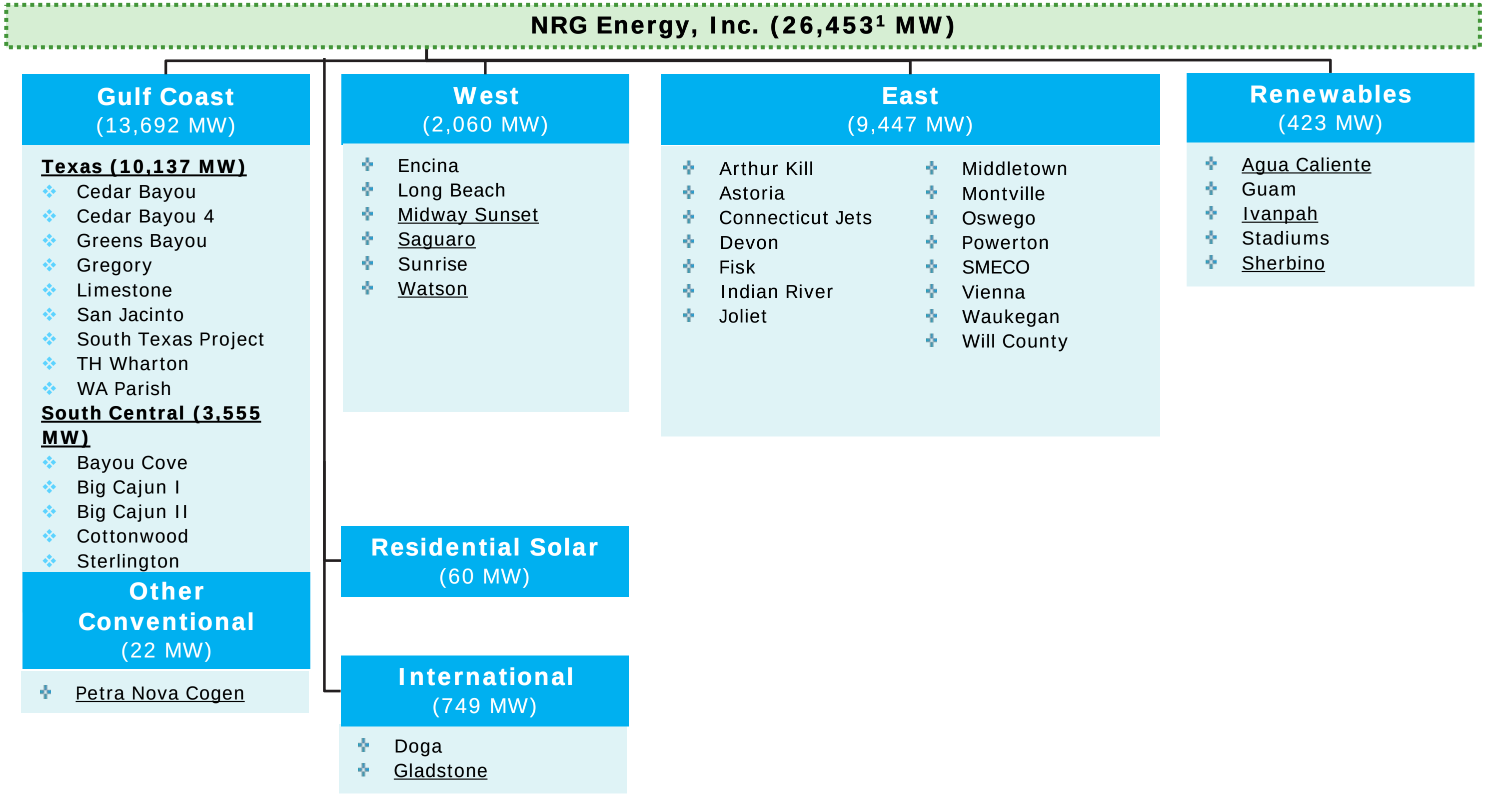
[1] Includes cost-to-achieve spend of $44 MM; [2] Also includes International and Renewables. Includes growth capital spend related to Canal 3; [3] Includes investments and acquisitions; [4] Includes net debt proceeds, cash grants and third-party contributions

Generation Organizational Structure



NRG Energy, Inc. (26,453[1] MW)

Gulf Coast
(13,692 MW)

Texas (10,137 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
(2,060 MW)
- Encina
- Long Beach
- Midway Sunset
- Saguaro
- Sunrise
- Watson

Residential Solar
(60 MW)

International
(749 MW)
- Doga
- Gladstone

East
(9,447 MW)
- Arthur Kill
- Astoria
- Connecticut Jets
- Devon
- Fisk
- Indian River
- Joliet
- Middletown
- Montville
- Oswego
- Powerton
- SMECO
- Vienna
- Waukegan
- Will County

Renewables
(423 MW)
- Agua Caliente
- Guam
- Ivanpah
- Stadiums
- Sherbino

LEGEND

Equity Investments

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[1] Capacity controlled by NRG as of 9/30/2018

Recourse / Non-Recourse Debt

($ millions)	**9/30/2018**	**6/30/2018**	**3/31/2018**	**12/31/2017**
Recourse Debt				
Term Loan Facility	$ 1,857	$ 1,862	$ 1,867	$ 1,872
Senior Notes	4,269	4,801	4,845	4,845
Convertible Notes	575	575	-	-
Tax Exempt Bonds	466	465	465	465
Revolver	-	26	-	-
Capital Lease	2	4	4	4
Recourse Debt and Capital Lease Subtotal	**$ 7,169**	**$ 7,733**	**$ 7,181**	**$ 7,186**
Non-Recourse Debt				
NRG Yield[1]	-	5,970	6,038	6,083
Renewables[1] (including capital leases)	185	1,775	2,756	2,783
Conventional	84[2]	657	613	586
Non-Recourse Debt Subtotal	**$ 269**	**$ 8,362**	**$ 9,407**	**$ 9,452**
Total Debt	**$ 7,438**	**$ 16,095**	**$ 16,588**	**$ 16,638**

Note: Debt balances exclude discounts and premiums

[1] Balance as of 9/30/2018 includes $86 MM of Agua Borrower I and $70 MM of Guam debt; balances as of 6/30/2018, 3/31/2018, and 12/31/2017 includes debt associated with NRG's interest in NRG Yield and the Renewables platform; [2] Includes Midwest Gen capacity monetization debt of $78 MM

Pro Forma Debt Analysis

($ millions)

NRG Consolidated Debt as of 6/30/2018[1]	**$16,095**
Less:	
Impact of divestitures - primarily NYLD (now Clearway Energy) and Renewables[1]	(8,062)
Corporate Term Loan and Midwest Gen debt amortization during 3Q18	(45)
Repayment of Corporate revolver	(26)
Remaining convertible note proceeds for deleveraging	(524)
NRG consolidated debt as of 9/30/2018	**$7,438**
Remaining Midwest Gen debt amortization	(78)
Guam debt	(70)
Agua debt (sale expected to close 2019)	(86)
Resi Solar / Other non-recourse debt	(35)
NRG corporate debt as of 9/30/2018	**$7,169**
Transformation plan deleveraging (target 3.0x)	(640)
Corporate Term Loan Amortization	(5)
NRG corporate debt as of 12/31/2018	**$6,524**

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[1] Includes debt held at NRG Yield (now Clearway Energy) and the Renewables platform prior to the sale of the assets and subsequent treatment as discontinued operations with respect to NRG's balance sheet

Announced Asset Sales

	Status	$ MM
Transformation Plan Asset Sales:		
Asset Sales in 2H17[1]	Closed	$150
Renewables / NRG Yield Interest	Closed	1,348
South Central	Targeted to close 4Q18	1,000
Buckthorn Solar	Closed	42
Carlsbad	Targeted to close 1Q19	365
Agua Caliente	Targeted to close 1Q19	120
BETM	Closed	70
Spanish Town and Keystone & Conemaugh	Closed	12
Transformation Plan Total Proceeds		**$3,107**
Asset Sales Outside of Transformation Plan:		
Canal 3	Closed	130
Total Proceeds[2]		**$3,237**

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[1] Includes drop down proceeds for TE Holdco (25%) $42 MM and SPP $71 MM to NRG Yield and sale proceeds for MN Wind $37 MM; [2] Excludes working capital and other purchase price adjustments

Incremental Transformation Plan

($ millions)

	2018	2019	2020
Cost Savings	$500	$590	$590
Margin Enhancements	30	135	215
EBITDA Impact	**$530**	**$725**	**$805**
Maintenance Capex	30	50	50
Working Capital	100	49	-
FCFbG Impact	**$660**	**$824**	**$855**
Annual EBITDA Change		***195***	***80***
Annual FCFbG Change		***164***	***31***

Appendix:
Reg. G Schedules

Reg. G: Q3 2018 YTD Free Cash Flow before Growth

($ millions)		QTD 9/30/2018		YTD 9/30/2018
Adjusted EBITDAR	**$**	**682**	**$**	**1,596**
Less: EME operating lease expense		(5)		(16)
Adjusted EBITDA	**$**	**677**	**$**	**1,580**
Interest payments		(132)		(344)
Income tax		1		(8)
Collateral / working capital / other		(144)		(470)
Cash Flow from Operations (continuing operations)	**$**	**402**	**$**	**758**
Gain on Sale of Land		-		3
Cost-to-Achieve[1]		27		71
GenOn Settlement[2]		132		132
Collateral[3]		27		45
Adjusted Cash Flow from Operations	**$**	**588**	**$**	**1,009**
Maintenance capital expenditures, net		(30)		(135)
Environmental capital expenditures, net		(1)		(1)
Distributions to non-controlling interests		(1)		(17)
Consolidated Free Cash Flow before Growth	**$**	**556**	**$**	**856**

[1] Includes costs associated with the Transformation Plan announced on 7/12/2017; [2] Includes settlement consideration of $261 MM, transition services credit of $28 MM, and pension contribution of $13 MM, less $151 MM repayment of intercompany revolver loan, accrued interest and fees of $12 MM, certain other balances due to NRG of $6 MM; [3] Includes $15 MM return of collateral to GenOn

Reg. G: 2018 and 2019 Guidance

Appendix Table A-1: 2018 and 2019 Guidance

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

($ millions)	2018 Previous Guidance	2018 Updated Guidance	2019 Guidance
Total Adjusted EBITDA	**$2,800 - $3,000**	**$1,700 - $1,800**	**$1,850 - $2,050**
Interest payments	(785)	(445)	(350)
Income tax	(40)	(15)	(15)
Working capital / other assets and liabilities	40	0	(80)
Adjusted Cash Flow from Operations	**$2,015 - $2,215**	**$1,240 - $1,340**	**$1,405 - $1,605**
Maintenance capital expenditures, net	(210) - (240)	(170) - (180)	(145) – (165)[1]
Environmental capital expenditures, net	(0) - (5)	(0) - (5)	(0) - (5)
Distributions to non-controlling interests	(220) - (250)[2]	(10) - (20)	-
Free Cash Flow before Growth	**$1,550 - $1,750**	**$1,050 - $1,150**	**$1,250 - $1,450**

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[1] 2019 includes ~$25 MM for TX reliability projects and Cottonwood; [2] Includes NRG Yield distributions to public shareholders, and Capistrano and Solar distributions to non-controlling interests

Reg. G

Appendix Table A-2: Third Quarter 2018 Adjusted EBITDA Reconciliation by Operating Segment

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

($ millions)	**Gulf Coast**	**East / West [1]**	**Generation**	**Retail**	**Corp / Elim**	**Total**
Income / (Loss) from Continuing Operations	**417**	**178**	**595**	**(127)**	**(162)**	**306**
Plus:						
Interest expense, net	-	10	10	1	105	116
Income tax	-	-	-	-	7	7
Loss on debt extinguishment	-	-	-	-	19	19
Depreciation and amortization	43	30	73	30	9	112
ARO Expense	9	4	13	-	-	13
Contract amortization	2	-	2	-	-	2
Lease amortization	-	(2)	(2)	-	-	(2)
EBITDA	**471**	**220**	**691**	**(96)**	**(22)**	**573**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	2	25	27	-	-	27
Reorganization costs	1	2	3	6	18	27
Deactivation costs	-	-	-	-	3	3
Gain on sale of business	-	1	1	-	(14)	(13)
Other non-recurring charges	1	(12)	(11)	-	2	(9)
Mark to market (MtM) (gains)/losses on economic hedges	(268)	(22)	(290)	359	-	69
Adjusted EBITDA	**207**	**214**	**421**	**269**	**(13)**	**677**

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[1] Includes International, Renewables and Generation eliminations

Reg. G

Appendix Table A-3: Third Quarter YTD 2018 Adjusted EBITDA Reconciliation by Operating Segment

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

($ millions)	**Gulf Coast**	**East / West [1]**	**Generation**	**Retail**	**Corp / Elim**	**Total**
Income / (Loss) from Continuing Operations	**156**	**146**	**302**	**733**	**(434)**	**601**
Plus:						
Interest expense, net	-	46	46	2	301	349
Income tax	-	1	1	-	18	19
Loss on debt extinguishment	-	-	-	-	22	22
Depreciation and amortization	128	131	259	86	25	370
ARO Expense	21	12	33	-	-	33
Contract amortization	7	1	8	-	-	8
Lease amortization	-	(6)	(6)	-	-	(6)
EBITDA	**312**	**331**	**643**	**821**	**(68)**	**1,396**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	5	47	52	-	1	53
Acquisition-related transaction & integration costs	-	-	-	2	3	5
Reorganization costs	5	5	10	10	50	70
Deactivation costs	-	10	10	-	8	18
Gain on sale of business	-	2	2	-	(29)	(27)
Other non-recurring charges	27	13	40	3	10	53
Impairments	-	74	74	-	-	74
Mark to market (MtM) (gains)/losses on economic hedges	14	5	19	(81)	-	(62)
Adjusted EBITDA	**363**	**487**	**850**	**755**	**(25)**	**1,580**

[1] Includes International, Renewables and Generation eliminations

Reg. G

Appendix Table A-4: Third Quarter 2017 Adjusted EBITDA Reconciliation by Operating Segment

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

($ millions)	Gulf Coast	East / West [1]	Generation	Retail	Corp / Elim	Total
Income / (Loss) from Continuing Operations	**155**	**117**	**272**	**72**	**(159)**	**185**
Plus:						
Interest expense, net	-	24	24	1	111	136
Income tax	-	-	-	-	1	1
Depreciation and amortization	69	59	128	28	7	163
ARO Expense	4	3	7	-	-	7
Contract amortization	3	1	4	(1)	-	3
Lease amortization	-	(2)	(2)	-	-	(2)
EBITDA	**231**	**202**	**433**	**100**	**(40)**	**493**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	(6)	14	8	-	(1)	7
Acquisition-related transaction & integration costs	-	-	-	-	3	3
Reorganization costs	3	-	3	5	4	12
Deactivation costs	-	2	2	-	3	5
Other non-recurring charges	(1)	(3)	(4)	1	7	4
Mark to market (MtM) (gains)/losses on economic hedges	(135)	(10)	(145)	173	-	28
Adjusted EBITDA	**92**	**205**	**297**	**279**	**(24)**	**552**

[1] Includes International, Renewables and Generation eliminations

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Appendix Table A-5: Third Quarter YTD 2017 Adjusted EBITDA Reconciliation by Operating Segment

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

($ millions)	Gulf Coast	East / West [1]	Generation	Retail	Corp / Elim	Total
Income / (Loss) from Continuing Operations	**50**	**133**	**183**	**380**	**(447)**	**116**
Plus:						
Interest expense, net	-	74	74	3	349	426
Income tax	-	2	2	(9)	10	3
Depreciation and amortization	207	178	385	81	24	490
ARO Expense	11	9	20	-	-	20
Contract amortization	10	3	13	-	-	13
Lease amortization	-	(6)	(6)	-	-	(6)
EBITDA	**278**	**393**	**671**	**455**	**(64)**	**1,062**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	15	43	58	-	(11)	47
Acquisition-related transaction & integration costs	-	-	-	-	3	3
Reorganization costs	3	-	3	5	10	18
Deactivation costs	-	3	3	-	7	10
Other non-recurring charges	(25)	-	(25)	1	16	(8)
Impairments	42	18	60	-	-	60
Mark to market (MtM) (gains)/losses on economic hedges	(152)	(11)	(163)	154	-	(9)
Adjusted EBITDA	**161**	**446**	**607**	**615**	**(39)**	**1,183**

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[1] Includes International, Renewables and Generation eliminations

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Appendix Table A-6: 2018 and 2019 Adjusted EBITDA Guidance Reconciliation: The following table summarizes the calculation of Adjusted EBITDA providing reconciliation to net income:

	Previous 2018 Adjusted EBITDA Guidance		Updated 2018 Adjusted EBITDA Guidance		2019 Adjusted EBITDA Guidance	
($ millions)	**Low**	**High**	**Low**	**High**	**Low**	**High**
Income from Continuing Operations[1]	410	610	405	505	965	1,165
Income tax	20	20	15	15	15	15
Interest Expense	785	785	445	445	350	350
Depreciation, Amortization, Contract Amortization, and ARO Expense	1,180	1,180	490	490	430	430
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	135	135	65	65	40	40
Other Costs[2]	270	270	280	280	50	50
Adjusted EBITDA	**$2,800**	**$3,000**	**$1,700**	**$1,800**	**$1,850**	**$2,050**

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[1] For purposes of guidance, discontinued operations are excluded and fair value adjustments related to derivatives are assumed to be zero; [2] 2018 includes impairments, loss on debt extinguishment, deactivation costs, and cost-to-achieve expenses; 2019 includes deactivation costs and cost-to-achieve expenses

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Appendix Table A-7: Expected Full Year 2018 and 2019 Adjusted EBITDA Reconciliation for Midwest Gen

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

($ millions)	**2018**	**2019**
Net (loss)/income	**69**	**83**
Plus:		
Depreciation, Amortization, Contract Amortization, and ARO Expense	50	50
EBITDA	**119**	**133**
Deactivation costs	3	-
Mark to market (MtM) losses on economic hedges	3	-
Plus: Operating lease expense	22	22
Adjusted EBITDAR	**147**	**155**
Less: Operating lease expense	(22)	(22)
Adjusted EBITDA - Standalone	**$125**	**$135**

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Appendix Table A-8: XOOM Energy Adjusted EBITDA Guidance: The following table summarizes the calculation of Adjusted EBITDA providing reconciliation to net income:

($ millions)	**2018**
Net income / (loss)	**11**
Plus:	
Depreciation, Amortization, Contract Amortization, and ARO expense	34
Adjusted EBITDA	**$45**

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Appendix Table A-9: 2018 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 Divestitures Announced**
Net Income[1]	**206**
Plus:	
Income tax	25
Interest expense, net	320
Depreciation, Amortization, Contract Amortization, and ARO Expense	577
EBITDA	1,128
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	77
Adjusted EBITDA	**1,205**
Interest payments	(320)
Collateral / working capital / other	(57)
Adjusted Cash Flow from Operations	**828**
Maintenance capital expenditures, net	(65)
Distributions to non-controlling interests	(173)
Free Cash Flow before Growth - Consolidated	**$590**

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[1] For purposes of guidance, fair value accounting related to derivatives are assumed to be zero

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Appendix Table A-10: Pro Forma Adjusted EBITDA: The following table summarizes the calculation of Adjusted EBITDA providing reconciliation to net income:

($ millions)	**Previous Pro Forma** **2018**
GAAP Net Income[1]	303
Income tax	20
Interest Expense	402
Depreciation, Amortization, Contract Amortization, and ARO Expense	485
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	123
Other Costs[2]	267
Adjusted EBITDA	**$1,600**

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[1] For purposes of guidance, discontinued operations are excluded and fair value accounting related to derivatives are assumed to be zero; [2] Includes deactivation costs, reorganization costs associated with the Transformation Plan, 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.