NRG Energy Inc.

Fourth Quarter 2016 Earnings Presentation

February 28, 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 anticipated benefits of acquisitions, 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 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, GenOn's ability to continue as a going concern, the inability to maintain or create successful partnering relationships, our ability to operate our businesses efficiently including NRG Yield, 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 February 28, 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 Earnings 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

Business Highlights

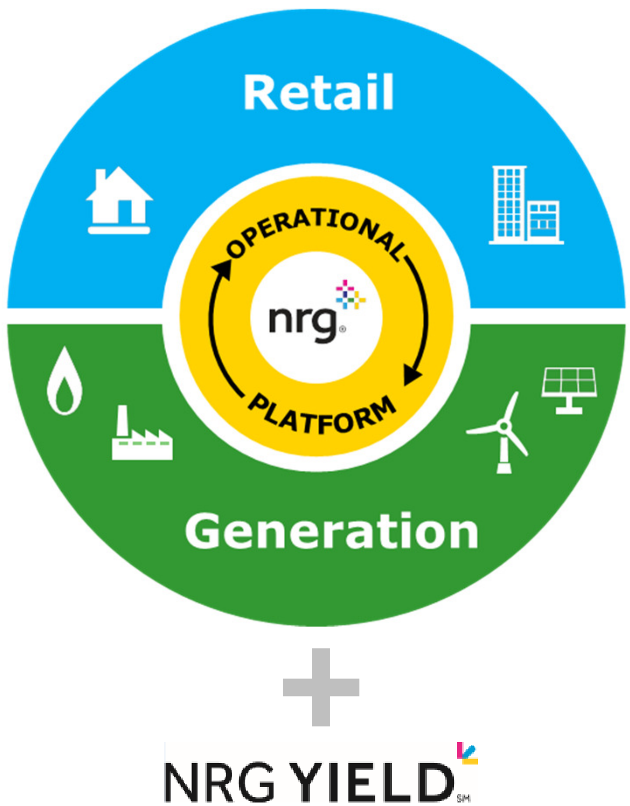
- ☑ **Integrated Platform Delivered Strong 2016 Financial and Operational Results:**
  - ☑ Top decile safety: 2nd best safety performance on record
  - ☑ Achieved $3,257 MM Adjusted EBITDA and $1,209 MM Free Cash Flow before Growth (FCFbG)
  - ☑ Retail delivered 3rd year in a row of EBITDA growth with $811 MM Adjusted EBITDA in 2016
  - ☑ Reaffirming 2017 financial guidance of $2,700-$2,900 MM Adjusted EBITDA and $800-$1,000 MM FCFbG

- ☑ **Successful Execution on Key 2016 Initiatives:**
  - ☑ Continued simplification and streamlining of NRG structure
  - ☑ Executed on cost reduction, deleveraging and asset sales
  - ☑ Strengthened NRG Yield with dedicated management team and 1.7 GW renewable asset acquisition
  - ☑ Completed coal to natural gas conversions and Petra Nova project on time and on budget

- ☑ **Continuing to Strengthen our Platform:**
  - ☑ Continuing to enhance platform with next phase of strategic priorities
  - ☑ Expanding discretionary deleveraging program by $200 MM; total of $600 MM for 2017
  - ☑ Adding 234 net MW of solar assets to ROFO pipeline with NRG Yield

NRG Value Proposition

A Differentiated Business Model…



…Underpinned by a Unique Value Proposition

- ☑ **Integrated Power Platform:** Largest competitive generation portfolio matched with leading retail business
- ☑ **Stable Base of Earnings:** 75% of economic gross margin[1] from fixed sources counter cyclical or non-correlated to natural gas (retail, capacity, contracted revenues)
- ☑ **Dynamic Regional Strategies:** Portfolio aligned to regional market dynamics and opportunities
- ☑ **Platform for Growth:** Ability to capitalize on growth opportunities and quickly replenish capital through NRG Yield partnership
- ☑ **Visible and Strong Free Cash Flow:** Robust cash flows underpinned by prudent balance sheet management

NRG Well-Positioned as the Premier Integrated Competitive Power Company

[1] Economic gross margin is defined as the sum of energy, capacity, retail and other revenue, less cost of fuel and other cost of sales

Executing on Strategic Priorities

NRG Focus

Strategic Priorities:	2016 Execution	2017 +
1 **Simplifying & Streamlining the Business**	☑ Focus on core Generation - Retail business ☑ Reintegrated Renewables business ☑ **$539 MM** total cost savings	**Focus on Continuous Improvement (forNRG)** **Significant Capex Reductions**
2 **Repositioning Our Portfolio**	☑ **$550 MM** conventional asset sales ☑ **1.7 GW** of solar and wind acquired ☑ **2.2 GW** of coal to gas conversions	**Targeting Additional Value-Enhancing Asset Sales**
3 **Strengthening the Balance Sheet**	☑ Cycle-appropriate capital allocation ☑ Recalibrated dividend policy ☑ **$1 Bn** corporate debt reduction[2] ☑ **$6 Bn** near-term maturities extended ☑ **$345 MM** preferred equity repurchased	**Focus on Deleveraging and Disciplined Capital Allocation**

Business Review Committee Focus[1]

To review and make recommendations on:

1. **Operational and Cost Excellence Initiatives**
2. **Potential Portfolio and/or Asset De-consolidations, Dispositions and Optimization**
3. **Capital Structure and Allocation**

NRG Strategic Priorities Result in Increased Financial Flexibility

[1] On 2/13/17, NRG announced a cooperation agreement with Elliott Management and Bluescape Energy Partners, including the formation of a five-person ad hoc committee of the Board – the Business Review Committee (BRC); [2] Comprised of 2015 corporate debt reduction of $246 MM (cash cost of $226 MM) and 2016 corporate debt reduction of $774 MM (cash cost of $894 MM including $120 MM of debt extinguishment fees)

1) Streamlining the Business

NRG Total Costs ($ Bn)

Exceeded Total Cost Reduction Target

- ☑ Achieved **$539 MM** total cost reduction through 2016
- ☑ Exceeded original $400 MM target

forNRG℠

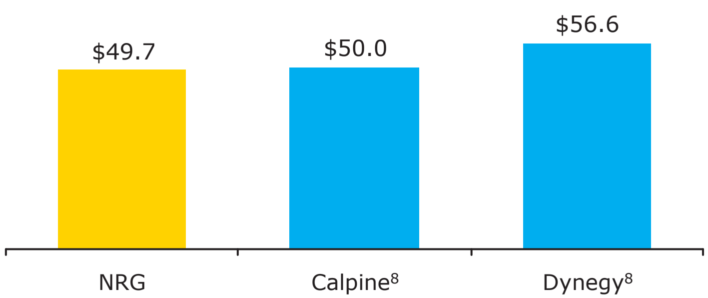
Streamlining Efforts Result in $539 MM Cost Reduction

[1] Includes fixed and variable O&M, $71.8 MM associated with plant sales (Shelby, Seward, Rockford, Aurora)

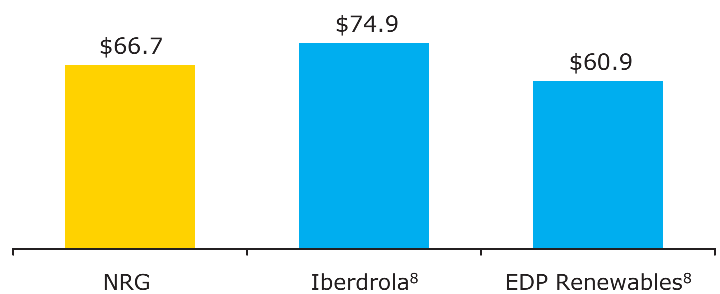
1) Unpacking the NRG Cost Structure[1]

$ millions	Generation	Retail	Renewables	NRG Yield
2016 Cost (O&M + SG&A)	$2,233	$838	$201	$255
2016 Maintenance Capex	$298	$27	$14	$16
TOTAL 2016 Costs	$2,531	$865	$215	$271
Excluded Costs & Other Adjustments[2]	($400)[3]	($3)	($28)	($8)
Adjusted Cost Basis	**$2,131**	**$862**	**$187**	**$263**
Units[4]	42,869 MW[3]	6.733 MM RCE	2,053 MW	6,145 MW[5]
Cost Metric	***$49.70/kW***	***$128/RCE***	***$91.25/kW***	***$42.80/kW***
			$66.65/kW[6] ***Combined Renewables[6]***	

Generation Benchmarking ($/kW)



Renewables Benchmarking[7] ($/kW)



Focused on Continuous Improvement; More to Come

[1] NRG costs per 2016 . Slide excludes corporate segment - see slide 35 for details; [2] Comprised of deactivation, asset retirement obligation accretion, contract amortization, gains/losses on asset disposals, operating lease expenses and operating costs and capital expenditures for nuclear asset (STP); [3] Adjusted to exclude $235 MM operating costs and capital expenditures for STP and corresponding capacity; [4] Units are Total Capacity for Generation, Renewables and NRG Yield, and RCE for Retail; RCE = Residential customer equivalent, which is calculated using electric and natural gas retail volumes and volumetric equivalents for non-commodity retail; [5] Includes 1,453 MWt of Thermal assets and our proportional ownership of equity method investments; [6] Average cost of renewables including assets in NRG Yield but operated by Renewables segment (details on slide 35); [7] Peers selected based on those with publicly available data; [8] Based on 2016 filings and investor presentations; Dynegy capacity adjusted to exclude 2017 acquisitions and retirements

2) Repositioning our Portfolio

2016 Repositioning Summary

☑ **Dispositions at Value:** 2.2 GW / $550 MM in Asset Sales

☑ **Asset Deactivations / Mothballed**: 1.1 GW in 2016

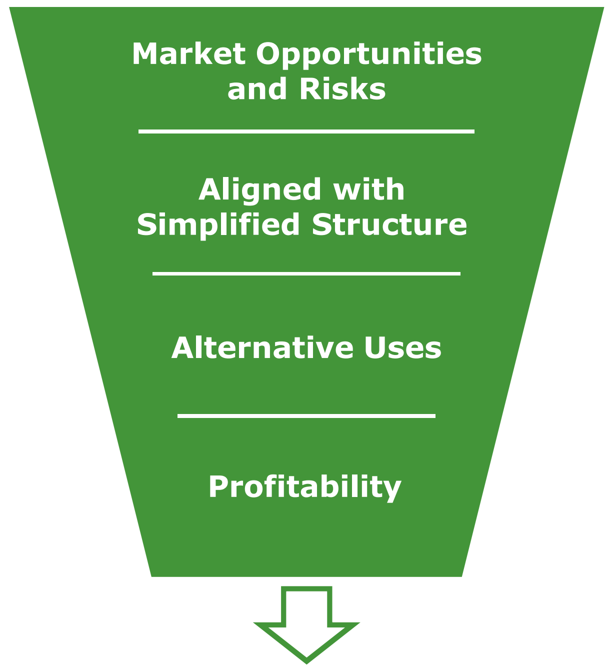
☑ **Modernizing the Fleet:**
- 2.2 GW coal to natural gas conversions
- Petra Nova CCS project complete

☑ **Capitalizing on Growth Opportunities:**
- Renewables: Acquired 1.7 GW of wind and solar assets
- Conventional: Carlsbad, Puente, Canal 3

☑ **GenOn Resolution Process Underway**

NRG Portfolio Continues to Undergo Rigorous Review Process

Key Decision Drivers

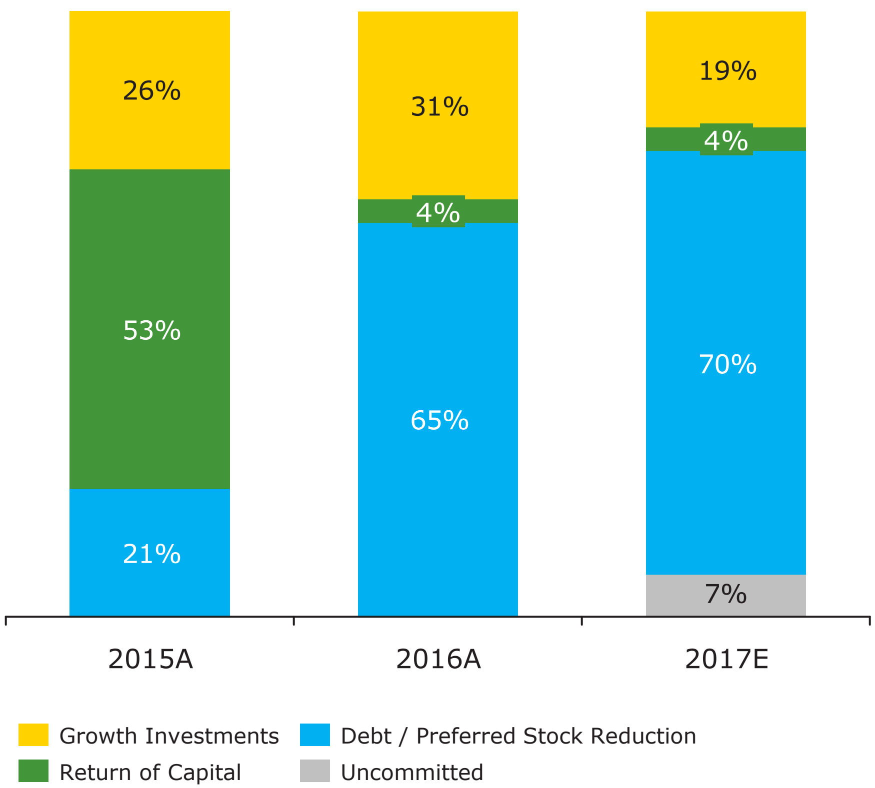


Optimized Portfolio

Repositioning our Fleet to Capitalize on Current Market Dynamics

3) Capital Allocation: Strengthening the Balance Sheet

Capital Allocation Mix



2017 Focus: Continued Deleveraging

- **Growth Capex**
  - Low commodity price environment
  - Focus on low cost options or areas for quick capital replenishment
- **Return of Capital**
  - Share Repurchases: attractive economics but on hold due to deleveraging
  - Dividend: appropriate for cyclical industry
- **Debt Reduction**
  - Enhances financial flexibility
  - Manage to cycle appropriate leverage
  - Attractive risk-adjusted return

Continued Focus on Deleveraging Ensures Capital Structure Aligned to Market Cycle

Financial Update

Financial Summary

Mass and Business Solutions (including C&I)

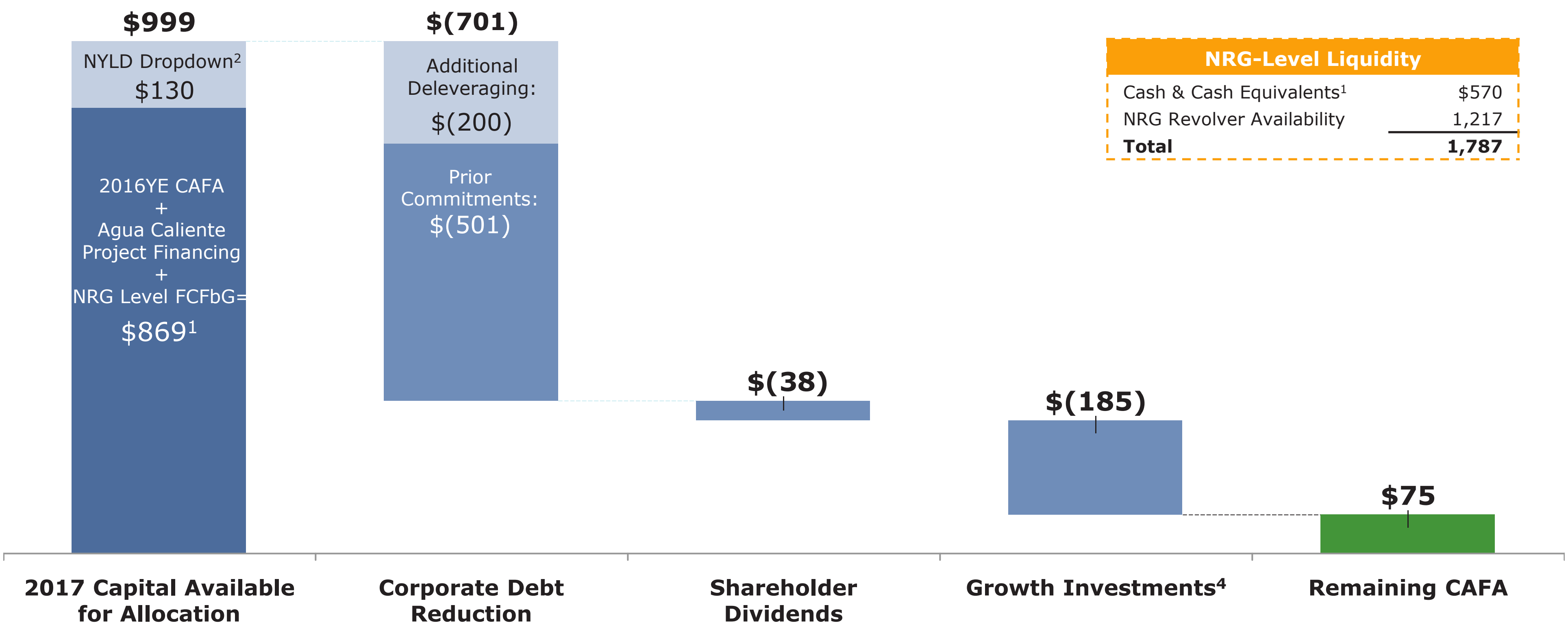
($ millions)	2016 Full Year Results	2017 Guidance Reaffirmed
Generation & Renewables[1]	$1,547	$1,135 – $1,255
Retail	811	700 – 780
NRG Yield	899	865
Adjusted EBITDA	**$3,257**	**$2,700 - $2,900**
Consolidated Free Cash Flow before Growth (FCFbG)	**$1,209**	**$800 - $1,000**
NRG-Level FCFbG	**$693**	**$700 - $900**

- Completed $1 Bn[2] of $1.4 Bn[3] planned corporate debt reduction program:
  - Annual interest savings of $87 MM[4] achieved plus $10 MM in annual preferred dividend savings
- Raising $258 MM from solar assets[5] and Agua Caliente drop down and additional project leverage
  - $128 MM in non-recourse net debt proceeds at Agua Caliente (closed in February 2017)
  - $130 MM NRG Yield proceeds for 31% of NRG's interest in Agua Caliente[6] and Utah solar assets
- Non-cash impairment charge of $1.2 Bn on fixed assets and goodwill
- Retail segment includes Mass customers and Business Solutions (C&I and other distributed and reliability products)

[1] Includes Corporate Segment; [2] Comprised of 2015 corporate debt reduction of $246 MM (cash cost of $226 MM) and 2016 corporate debt reduction of $774 MM (cash cost of $894 MM including $120 MM of debt extinguishment fees); [3] Includes $400 MM reserved for 2018 Senior Notes; [4] Reflects impact of term loan repricing announced on January 21, 2017; [5] NRG reached agreement on dropdown of Utah solar assets (Four Brothers and Three Cedars), representing 265 net MW, based on cash to be distributed in tax equity partnership with Dominion in Utah; [6] Represents 16% of the project as NRG currently owns 51% of the project (148 net MW)

2017 NRG-Level Capital Allocation

($ millions)



NRG-Level Liquidity	
Cash & Cash Equivalents[1]	$570
NRG Revolver Availability	1,217
Total	**1,787**

Retirement of 2018 Notes	$398
Reserve for Additional Debt Reduction	$200
Term Loan Amortization	$19
Midwest Gen Debt Amortization[3]	$80
Term Loan Refi Fees	$4

Expanding Allocation to Debt Reduction at Attractive Risk-Adjusted Returns

[1] Represents $570 MM cash & cash equivalents at NRG level on 12/31/16 less minimum cash reserves of $700 MM at NRG-level (net of $71 MM in NRG Level cash collateral postings) plus mid-point of NRG-level FCFbG guidance of $800 MM plus $128 MM of Agua Caliente project-level net financing proceeds closed on February 17, 2017; [2]Estimated proceeds, subject to working capital adjustments, from dropdown of Utah solar assets and 16% interest in Agua Caliente to NRG Yield (expected closing in next 60 days); [3] Represents 2017 capacity revenue sold of $80 MM against $253 MM monetized in 2016; [4] Net of financing

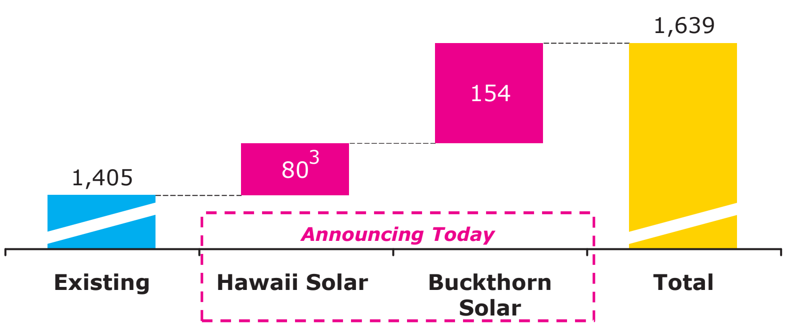
Drop Down Transaction and Related Financings

Completed Asset Re-Financings and Drop Down Agreement to NRG Yield; Expanded ROFO

Total cash proceeds of $307 MM from drop downs and additional non-recourse financings:

($ MM)	Utah Solar (265 net MW)	Agua Caliente (46 net MW)
Drop Down Proceeds[1]	$81	$48
Non-Recourse Financings	$49	$128
Total Cash Received:	**$130**	**$177**

Expanding the NYLD ROFO Pipeline (MW)



Proceeds Demonstrate Rapid Recycling of Capital on 1.5 GW Portfolio Acquisition

Entire SunEdison utility-scale transaction purchase price returned after first drop down

- Late stage backlog provides visible growth:
  - 154 MW Buckthorn Solar project, COD in 1H ’18
  - 80 MW[3] Hawaii Solar, COD in ’19
- Zero-cost option on remaining >1 GW pipeline

SunEdison Utility Acquisition Results to Date ($ MM)		
Total Transaction Purchase Price	Nov-16	($124)
Utah Solar Net Financing Proceeds Distributed to NRG	Dec-16	+$48
Utah Solar Dropdown Proceeds[2]	Mar-17	+$81
Total:		**+5 MM**

Expanded ROFO Pipeline Provides Further Opportunities to Grow and Recycle NRG-Level Capital through Partnership with NYLD

[1] Utah Solar represents 50% interest in Four Brothers and Three Cedars Assets (100% of NRG’s Interest) and Agua Caliente represents 16% interest (31% of NRG’s 51% interest); [2] Subject to adjustments for working capital and other post closing items; closing expected in next 60 days; [3] Reflects 110 MW related to 3 solar projects acquired by NRG, net of 30 MW that are not yet subject to the ROFO agreement

NRG's Capital Structure & Corporate Credit Metrics

($ millions)

Debt and Cash Balances As of 12/31/16

NRG Energy, Inc.

	Consolidated	Recourse
Total Debt:	$19,333	$7,795
Total Cash:	$1,973	$570

Dividends & Distributions

Project Company Management Service Payments

GenOn	NRG Yield	ROFO/ Other
Total Debt: $2,623	Total Debt: $5,798	Total Debt: $3,117

~ 11.5 Bn

LEGEND

Recourse Debt

Non-Recourse Debt (Excluded Project Sub)

	2016A	2017E
		Post-Capital Allocation
Recourse Debt *(12/31/2016)*[1]	**$7,795**	**~$7,795**
2018 Maturity Reserve		(398)
2017 Term Loan Amortization		(19)
Additional Debt Reduction		(200)
Pro Forma Corporate Debt		**~$7,200**
Actual / 2017 Mid-Point Adj. EBITDA	$3,257	$2,800
Less Adjusted EBITDA:		
GenOn[2]	(551)	(145)
NRG Yield	(899)	(865)
ROFO / Other[3]	(178)	(400)
Add:		
NRG Yield Distributions to NRG[4]	81	90
ROFO / Other Dividends to NRG[5]	91	110
Other Adjustments[6]	118	150
Total Recourse EBITDA	**$1,919**	**$1,740**
Corporate Debt/Corporate EBITDA	**4.06x**	**4.13x**
Cash & Cash Equivalents @ NRG-Level	$570	$645
Corporate Net Debt/Corporate EBITDA	**3.76x**	**3.75x**

Maintaining Balance Sheet Metrics In-Line With Targets

[1] Includes NRG Energy Inc. term loan facility, senior notes and tax exempt bonds; [2] Net of shared service payment by GenOn to NRG; reflects impact of monetization of hedges; [3] Includes Aqua Caliente, Ivanpah, Midwest Generation, Yield eligible assets, Sherbino, Capistrano, and international assets; increase in 2017 primarily from MWG following environmental compliance and Ivanpah ramp-up; [4] 2016A includes NYLD dividends to NRG of $81 MM; excludes Resi / DG dropdown proceeds of $80 MM and CVSR transaction proceeds of $180 MM, which if included per the NRG credit agreement would yield a Corporate Debt /EBITDA ratio of 3.58x; 2017 estimate based on NYLD dividends equivalent to $1.15/share annualized by Q4 and excluding impact of drop-down proceeds; [5] Distributions from NRG ROFO, MWG and other non-recourse project subsidiaries; increase in 2017 primarily from MWG following environmental compliance and Ivanpah ramp-up; [6] Reflects non-cash expenses (i.e. nuclear amortization, equity compensation, and bad debt expense) that are included in reported Adjusted EBITDA

Closing Remarks

2017 Priorities

- Deliver on our Financial and Operational Goals
- Finalize Comprehensive Resolution for GenOn
- Achieve Cost Efficiencies and Continue to Reposition Portfolio
- Focus on Debt Reduction and Financial Flexibility
- Identify and Execute on Growth Opportunities with High Returns and Quick Capital Replenishment

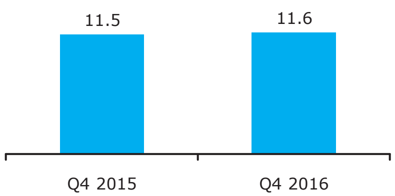
Q&A

Appendix: Operations

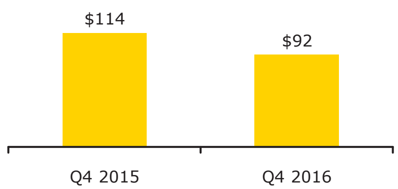
Year over Year Performance Drivers: Q4 Results

Gulf Coast

Generation (TWh)



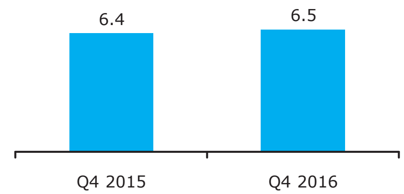
EBITDA ($ MM)



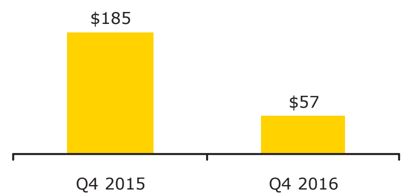
- **$22 MM lower Adjusted EBITDA due to:**
  - Lower realized energy margins in Texas from lower power prices partially offset by higher generation
  - Lower gross margin in South Central on lower contract margins due to higher supply costs and lower capacity revenues

East

Generation (TWh)



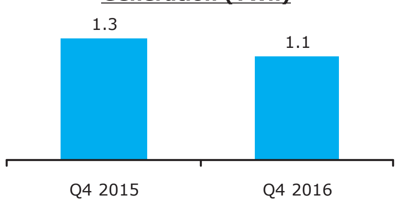
EBITDA ($ MM)



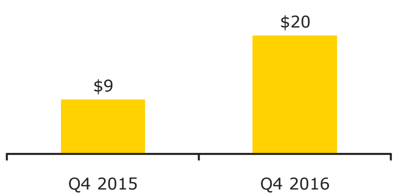
- **$128 MM lower Adjusted EBITDA due to:**
  - Lower energy and contract margins from lower economic dispatch and plant sales/deactivations
  - Lower capacity revenues due to plant sales, deactivations and lower pricing in PJM and NY

West

Generation (TWh)



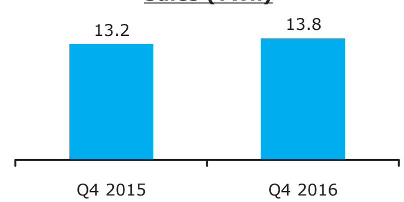
EBITDA ($ MM)



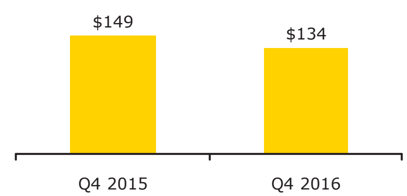
- **$11 MM higher Adjusted EBITDA**
  - Higher capacity revenues and lower operating costs

Retail

Sales (TWh)



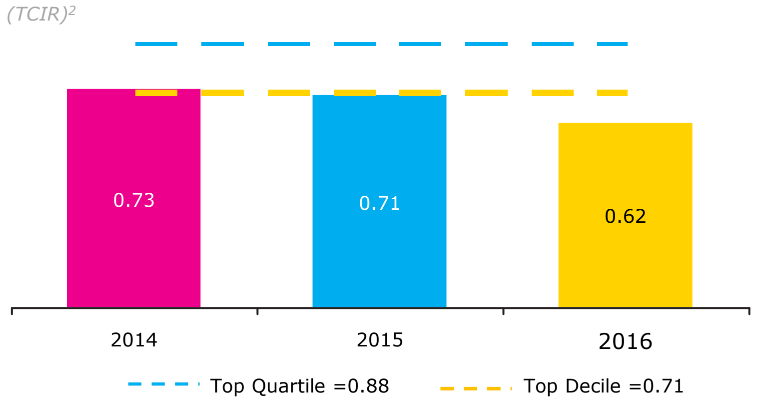
EBITDA ($ MM)



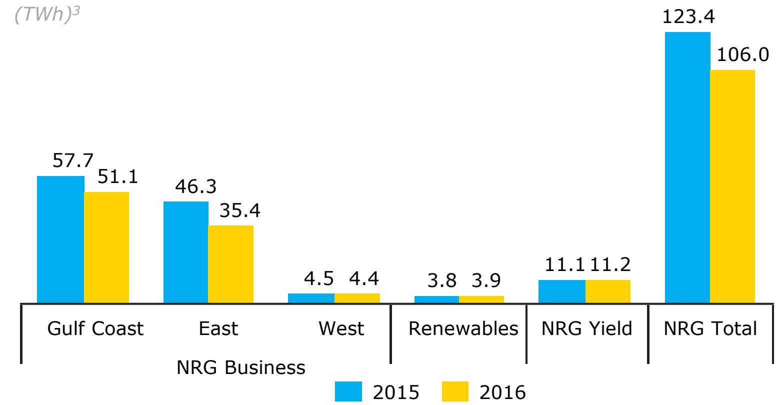
- **$15 MM lower Adjusted EBITDA due to:**
  - Increase in spend associated with customer growth initiatives

Generation/Business: Operational Metrics

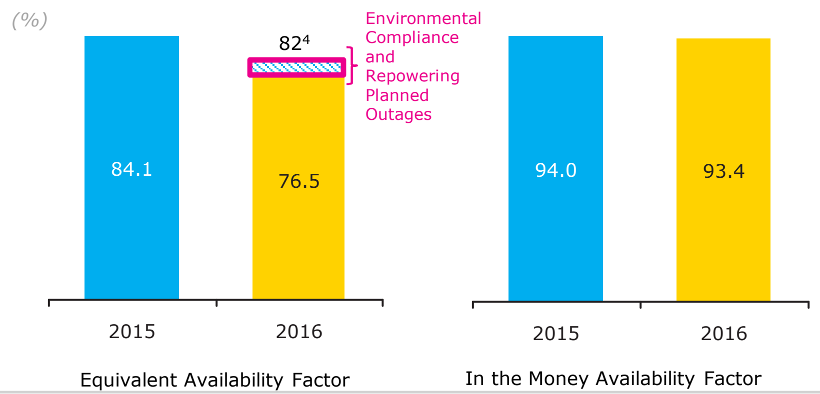
Safety[1]



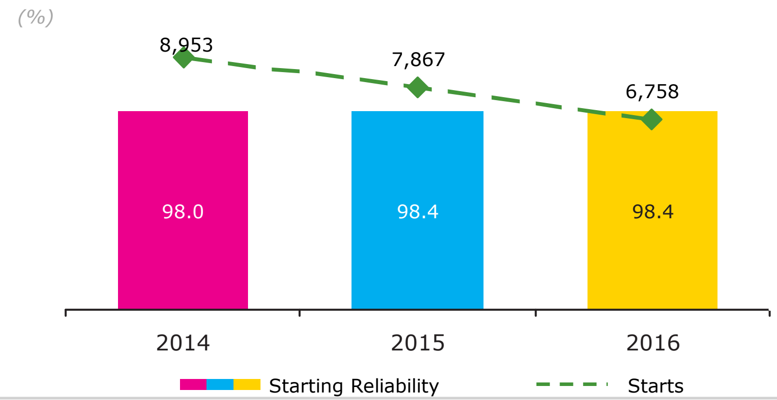
Production



Coal and Nuclear Availability EAF vs IMA[5]



Gas and Oil Starts and Reliability



Top Decile Safety and Strong Availability When Economics Justify (IMA)

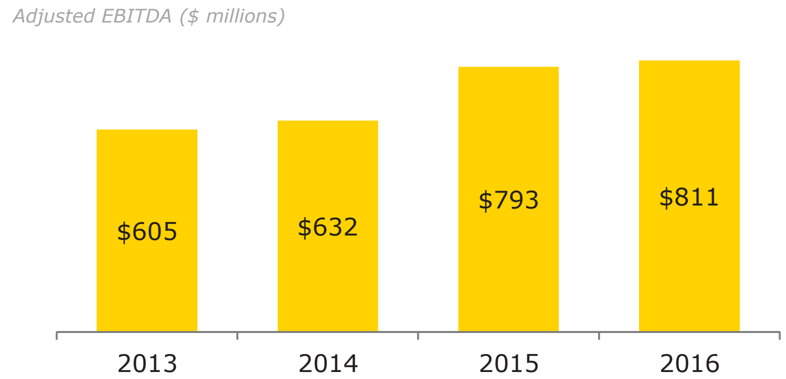
[1] Excludes Goal Zero, NRG Home Services and NRG Residential Solar; Top decile and top quartile based on EEI 2015 Total Company Survey results; [2] TCIR = Total Case Incident Rate; [3] All NRG-owned domestic generation; Excludes line losses, station service, and other items. Generation data presented above consistent with US GAAP accounting. Previous reports were pro-forma for acquisitions in prior periods; [4] Assumes normalized operations from prior period, removing only the planned outages associated with Environmental Compliance and Repowering projects in 2016 at Avon Lake, Joliet and New Castle; [5] In the Money Availability defined on slide 36

Retail: Operational Metrics

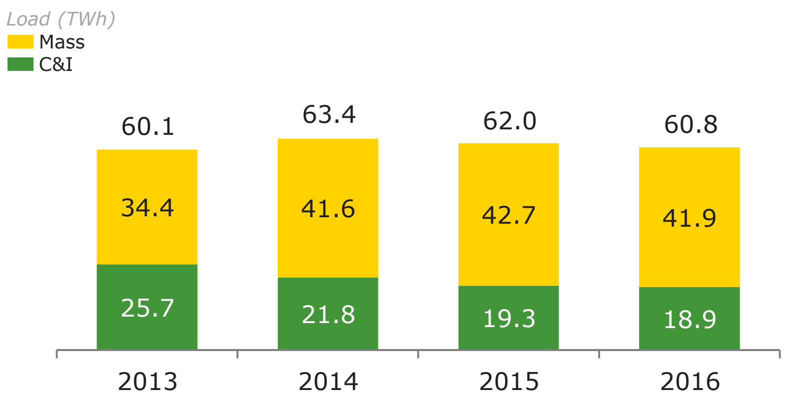
2016 Highlights

- Delivered 3rd year in a row of earnings growth with $811 MM of Adjusted EBITDA in 2016
- Expanded portfolio with the growth of ~63,000 recurring Mass customers over the year
- Overcame milder weather conditions vs 2015 with continuous improvement related cost efficiencies and favorable supply costs

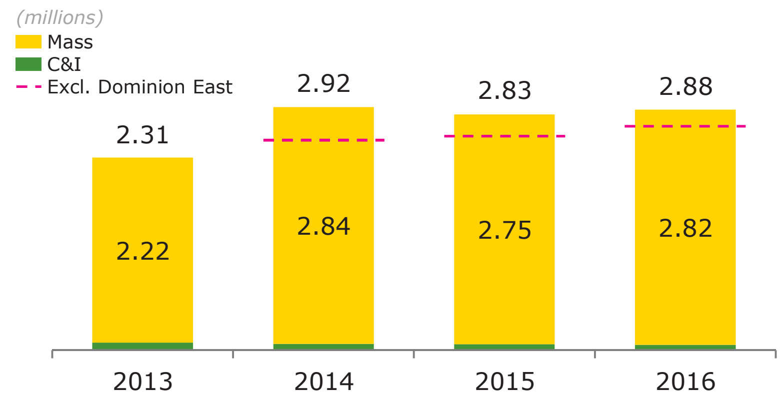
Earnings, excluding Residential Solar



Delivered Volume



Count[1]

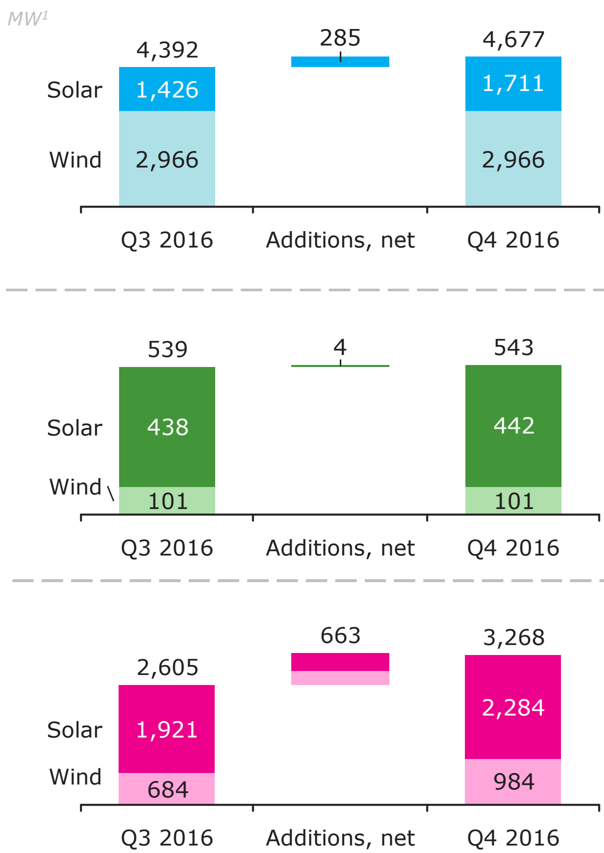


Another Strong Year Driven by Disciplined Execution and Low Supply Costs

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

Renewables: Portfolio Update

Quarter over Quarter Change



Key Q4 Updates

Operating Portfolio: 4,677 MW[1,2,3]

- ☑ 265 MW in Utah, operational and offered to NYLD
- ☑ 31% of NRG's 51% ownership (46 MW) in Agua Caliente offered to NYLD
- ☑ Transitioned 2,675 MW to self operations in 2016, adding Alta 1 in Q4

2017-2019 Backlog: 543 MW[4]

- ☑ Successfully re-contracted 154 MW Buckthorn Solar project
- ☑ Ramped community solar to 64 MW in construction across MA and MN

Utility–Scale and DG Pipeline: 3,268 MW[5]

- ☑ Utility-Scale wind and solar expansion in ISO-NE, ERCOT, CAISO
- ☑ Community Solar expansion into NY market
- ☑ DG growth across commercial, municipalities, and schools

Significant Scale and with a Substantial Pipeline for Future Growth

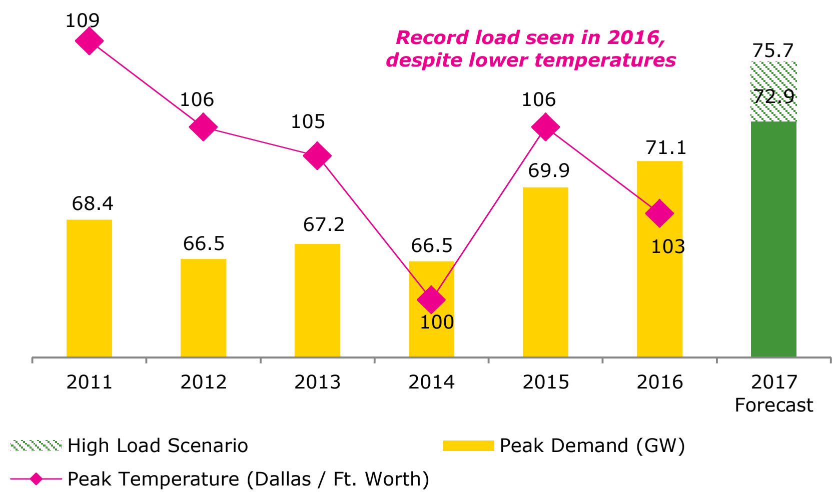
[1] 4.7 GW at NRG Consolidated, of which 2.6 GW is at NYLD; [2] MW amounts in AC; [3] NRG self-performs plant operations on 2.7 GW of the consolidated fleet of assets owned by NRG and NYLD and 224 MW on assets owned by third parties; [4] Backlog is defined as projects that are under construction, contracted, or awarded, and represents a higher level of execution certainty; [5] Pipeline is defined as projects that range from identified lead to shortlisted with an offtake and represents a lower level of execution certainty

Q4 Regulatory Update

	Markets Impacted	NRG Action	Timeline and Next Steps:
Zero Emissions Credits (ZECs) in NY & IL	NYISO, PJM	➢ NRG and others filed federal court challenges against the unlawful interference in FERC-jurisdictional markets ➢ Challenges follow on decision by the U.S. Supreme Court in Hughes v. Talen finding state interference in FERC-jurisdictional markets to be unlawful	➢ New York: Awaiting Judge's decision on Motion to Dismiss and anticipate a Summer trial ➢ Illinois: Lawsuit filed Feb. 14, with procedural schedule to come
Existing Asset Minimum Offer Price Rule (MOPR) in NY & PJM	NYISO, PJM	➢ NRG seeking FERC action to mitigate market interference by subsidized nuclear units	➢ Lack of quorum at FERC means decision likely be delayed
Capacity Performance Implementation	PJM	➢ PJM's filing allowing aggregation of seasonal resources is pro-competitive, and additional reason not to delay implementation of 100% Capacity Performance ➢ Some parties requested that FERC delay implementation of 100% Capacity Performance for another year, which would allow Base Capacity to continue participating for another auction	➢ Expect PJM proposal to go into effect prior to upcoming auction ➢ Expect no action by FERC on the complaints prior to 2017 auction
ERCOT Scarcity Pricing Reform	ERCOT	➢ NRG seeking RMR rule changes to reflect locational scarcity pricing ➢ NRG retained experts to examine ERCOT energy-only market design and recommend price formation improvements such as ORDC reforms and marginal losses	➢ RMR reform under serious discussion in ERCOT ➢ Pushing for approval of ORDC reforms and consideration of broader price formation reforms in 2017, including marginal losses

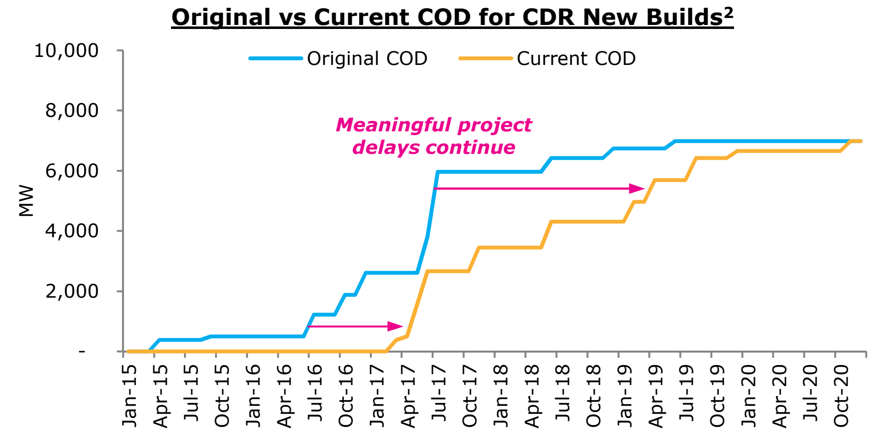
Market Outlook - ERCOT

ERCOT Seeing Record, Sustained Increases in Load[1]…



- Demand story continues in ERCOT with ~2% weather normalized load growth in 2016 and over 3% in Q4
- Multiple new winter peaks set this winter far exceeding the prior winter peak
- ERCOT made a significant upward revision to their load forecast

…Along with Conventional New Build Delays



- Persistently low power prices present challenges for development of new capacity
- Many of the new assets in the CDR have pushed back their commercial online date (COD) multiple times for multiple years
- Challenging economics stress existing resources as well, significantly increasing the likelihood of retirements

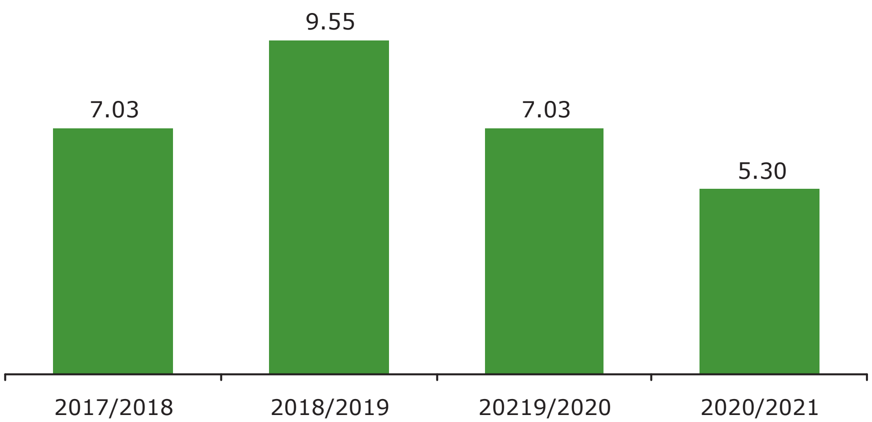
ERCOT Market Continues To Tighten Through Record Loads, Retirement Risk, and Delayed New Builds

[1] ERCOT, NOAA. High Load Scenario based on ERCOT Summer 2016 SARA Seasonal Load Adjustment of 2.8 GW; [2] ERCOT GIS Reports

Market Outlook - Northeast

New England: Capacity Prices Still Healthy

ISO-NE Capacity Prices ($/kW-mo)[1]



- NRG low cost fleet benefits from strong, reliability driven, capacity market
- Healthy price clear for 2020/2021 at $5.3/kW-mo ($174/MW-d)
- No new generation cleared in FCA 11 and none expected for next several years

PJM: Shift to CP Only Auction[2]

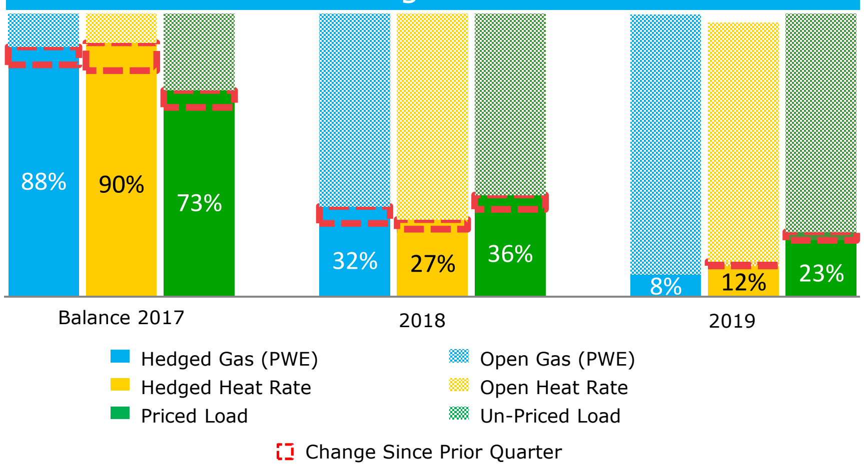
Market Driver	Outlook
100% CP Requirement	➢ 100% CP in 20/21 adds risk for ~17 GW of generation that cleared as base capacity in 19/20
Decreased Demand-side Participation	➢ Enhanced seasonal requirements add risk to ~10 GW of demand response and energy efficiency that cleared as base in 19/20
Fewer Imports	➢ Increasing requirements and limitations for imports
Zonal Transfer Ratios	➢ CETO:CETL ratios bolster potential for zonal price separation in COMED
Nuclear	➢ Unclear how subsidized IL nuclear stations will participate in capacity auction
Seasonal Aggregation	➢ Potential to pair summer and winter limited availability resources but alternative to CP delay
Stagnant Load	➢ RTO Reliability Requirements down 2% year-on-year

Northeast Capacity Markets Continue to Provide Stable Revenue

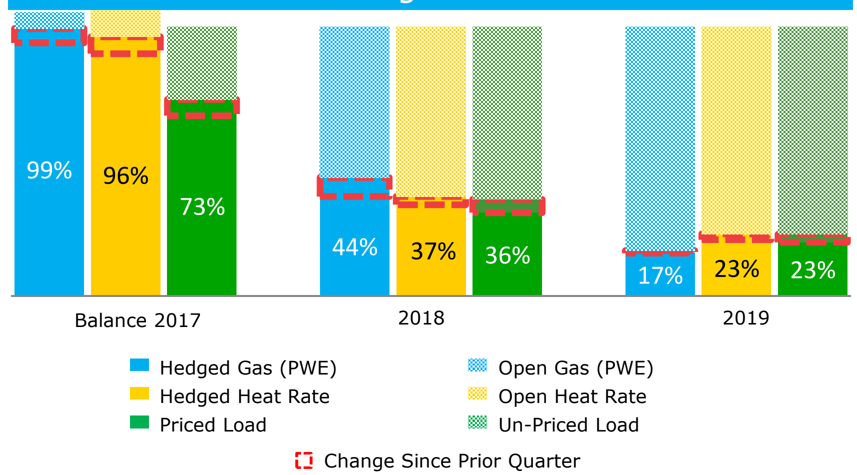
[1] ISONE; [2] PJM, NRG Estimates

Managing Commodity Price Risk

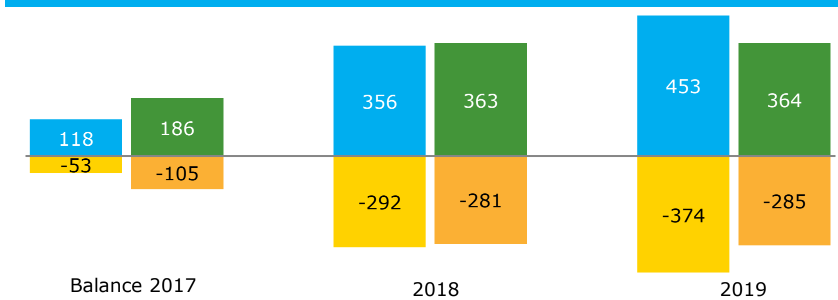
Total Portfolio Generation and Retail Hedge Position[1,2,5]



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



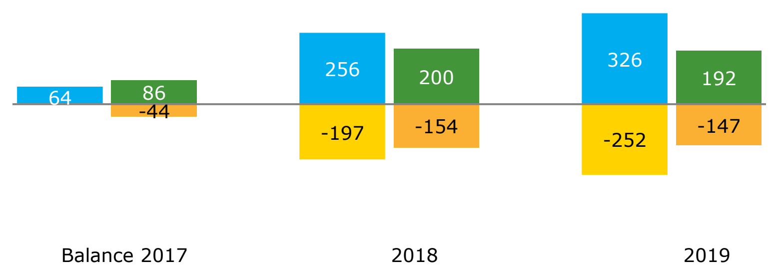
Total Portfolio Sensitivity to Gas Price and Heat Rate[1,3,5]



Henry Hub Gas as of 02/10	3.28	3.09	2.87

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]



Henry Hub Gas as of 02/10	3.28	3.09	2.87

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 02/10/2017, Balance 2017 reflects March 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 96% and 41% 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			GENON [7]	
	Balance 2017	2018	2019	Balance 2017	2018	2019	Balance 2017	2018	2019
Net Coal and Nuclear Capacity (MW)[2]	6,250	6,250	6,250	7,465	7,465	7,465	4,198	4,198	4,198
Forecasted Coal and Nuclear Capacity (MW)[3]	4,761	4,259	3,978	3,024	2,869	2,267	1,582	1,610	1,284
Total Coal and Nuclear Sales (GWh)[4]	32,938	22,256	8,807	23,867	5,292	474	12,165	1,925	14
Percentage Coal and Nuclear Capacity Sold Forward[5]	94%	60%	25%	107%	21%	2%	105%	14%	0%
Total Forward Hedged Revenues [6]	$1,209	$822	$440	$834	$163	$11	$444	$63	$0
Weighted Average Hedged Price ($ per MWh)[6]	$36.70	$36.93	$49.93	$34.96	$30.87	NA	$36.49	$32.69	NA
Average Equivalent Natural Gas Price ($ per MMBtu)[6]	$3.57	$3.81	$4.75	$3.48	$2.96	NA	$3.51	$3.13	NA
Gross Margin Sensitivities: Gas Price Sensitivity Up $0.50/MMBtu on Coal and Nuclear Units	$—	$56	$114	$65	$200	$212	$38	$117	$110
Gross Margin Sensitivities: Gas Price Sensitivity Down $0.50/MMBtu on Coal and Nuclear Units	$27	($55)	($107)	($22)	($142)	($145)	($4)	($79)	($78)
Gross Margin Sensitivities: Heat Rate Sensitivity Up 1 MMBtu/MWh on Coal and Nuclear Units	$35	$91	$87	$52	$108	$106	$27	$55	$52
Gross Margin Sensitivities: Heat Rate Sensitivity Down 1 MMBtu/MWh on Coal and Nuclear Units	($18)	($72)	($65)	($26)	($82)	($82)	($7)	($40)	($42)

[1] Portfolio as of 02/10/2017, Balance 2017 reflects March 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 02/10/2017which 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 02/10/2017and 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 2016 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.
[7] GenOn disclosure not additive to other regions

Commodity Prices

Forward Prices[1]	Bal-2017[2]	2018	2019	Annual Average for 2017-2019
NG Henry Hub ($/MMbtu)	$3.28	$3.09	$2.87	$3.08
PRB 8800 ($/ton)	$11.98	$12.23	$12.50	$12.24
NAPP MG2938 ($/ton)	$49.28	$47.00	$48.00	$48.09
ERCOT Houston Onpeak ($/MWh)	$39.34	$36.18	$33.87	$36.47
ERCOT Houston Offpeak ($/MWh)	$24.67	$22.11	$20.57	$22.45
PJM West Onpeak ($/MWh)	$36.47	$38.25	$36.21	$36.98
PJM West Offpeak ($/MWh)	$25.91	$26.52	$25.40	$25.94

[1] Prices as of 02/10/2017
[2] Represents March through December months

Modernizing the Portfolio

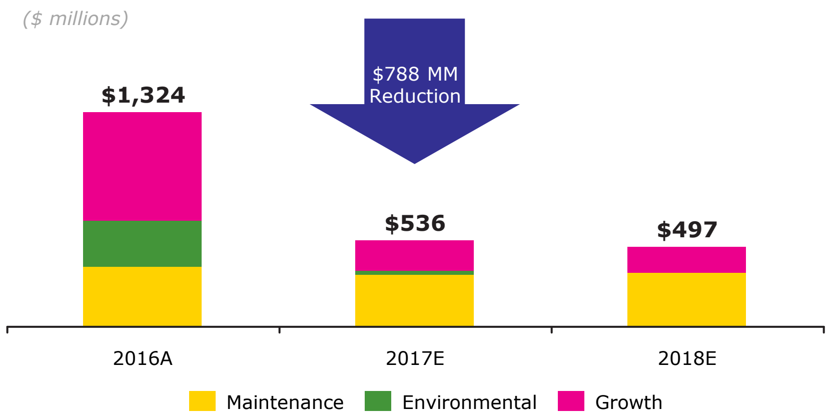
Delivering Major Projects

		MW	Project Description	Estimated COD
Fuel Conversions and Environmental Projects	Shawville 1-4[1]	597	Natural Gas	Complete
	Powerton 5 & 6	1,538	DSI & ESP Upgrade	Complete
	Petra Nova		Carbon Capture & EOR	Complete
	Joliet	1,326	Natural Gas	Complete
	New Castle 3-5[1]	325	Natural Gas	Complete
Growth Projects	Bacliff Peakers	360	New Generation	2Q 2017
	Buckthorn Wind	101	New Renewables	4Q 2017
	University of Pittsburgh Medical Center[2]		Combined Heat & Power	4Q 2017
	Carlsbad Peakers	527	New Generation	4Q2018
	Canal Peakers[3]	333	New Generation	4Q 2019
	Puente Peakers[3]	262	New Generation	2Q 2020

Converted 2.2 GW of Coal to Natural Gas

Shawville (597 MW)	Converted plant to closed circulating water system and new cooling tower which eliminated river water cooling
Joliet (1,326 MW)	Constructed 2 mile gas pipeline interconnections and metering and regulation station
New Castle (325 MW)	Capacity Factor went from 14.0% in 2015 on coal to 57.9% in 2016 on gas

Significant Reduction in Capex in 2017



[1] GenOn Facility; [2] NRG Yield acquisition; [3] Subject to applicable regulatory approvals and permits

Fuel Statistics

	4Q		Year To Date	
Domestic[1]	**2016**	**2015**	**2016**	**2015**
Coal Consumed (mm Tons)	6.0	5.6	27.3	37.6
PRB Blend	**75%**	**75%**	**71%**	**73%**
East	62%	65%	58%	62%
Gulf Coast	82%	82%	79%	82%
Bituminous	**13%**	**11%**	**16%**	**13%**
East	38%	26%	39%	29%
Lignite & Other	**12%**	**14%**	**13%**	**14%**
East	0%	9%	3%	9%
Gulf Coast	18%	18%	21%	18%
Cost of Coal ($/Ton)	**$ 35.92**	**$ 40.08**	**$ 38.45**	**$ 40.97**
Cost of Coal ($/mmBtu)	**$ 2.02**	**$ 2.30**	**$ 2.15**	**$ 2.33**
Cost of Gas ($/mmBtu)	**$ 2.69**	**$ 2.10**	**$ 2.34**	**$ 2.73**

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

4Q 2016 Generation & Operational Performance Metrics

(MWh 000's)	2016 Generation[1]	2015 Generation[1]	MWh Change	% Change	2016 EAF[2]	2016 NCF[3]	2015 EAF[2]	2015 NCF[3]
Gulf Coast – Texas	8,367	7,346	1,021	14%	82%	36%	82%	31%
Gulf Coast – South Central	3,217	4,118	(901)	(22%)	75%	34%	82%	44%
East	6,365	6,542	(178)	(3%)	77%	13%	87%	12%
West	1,104	1,348	(244)	(18%)	96%	8%	91%	10%
Renewables	915	1,000	(84)	(8%)	97%	40%	97%	40%
NRG Yield[4]	2,601	2,773	(172)	(6%)	98%	21%	98%	23%
Total	**22,569**	**23,126**	**(558)**	**(2%)**	**83%**	**21%**	**87%**	**20%**
Gulf Coast – Texas Nuclear	2,092	1,589	503	32%	83%	81%	63%	61%
Gulf Coast – Texas Coal	5,558	4,077	1,481	36%	80%	60%	84%	44%
Gulf Coast – South Central Coal	673	585	88	15%	59%	33%	90%	29%
East Coal	4,925	5,076	(151)	(3%)	73%	30%	90%	23%
Baseload	**13,247**	**11,327**	**1,921**	**17%**	**75%**	**44%**	**86%**	**32%**
Renewables Solar	360	336	24	7%	99%	42%	100%	44%
Renewables Wind	555	663	(109)	(16%)	96%	40%	96%	39%
NRG Yield Solar	213	226	(13)	(6%)	99%	21%	100%	22%
NRG Yield Wind	1,460	1,373	87	6%	97%	32%	96%	30%
Intermittent	**2,588**	**2,598**	**(11)**	**(0%)**	**97%**	**33%**	**97%**	**32%**
East Oil	48	100	(52)	(52%)	81%	0%	87%	1%
Gulf Coast – Texas Gas	717	1,680	(963)	(57%)	84%	6%	84%	14%
Gulf Coast – South Central Gas	2,544	3,533	(989)	(28%)	80%	35%	80%	48%
East Gas	1,391	1,367	24	2%	78%	8%	84%	9%
West Gas	1,104	1,348	(244)	(18%)	96%	8%	91%	10%
NRG Yield Conventional	431	669	(238)	(36%)	99%	10%	99%	15%
NRG Yield Thermal[4]	497	505	(8)	(2%)	95%	7%	92%	27%
Intermediate / Peaking	**6,734**	**9,202**	**(2,469)**	**(27%)**	**85%**	**9%**	**87%**	**13%**

[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

Full Year 2016 Generation & Operational Performance Metrics

(MWh 000's)	2016 Generation[1]	2015 Generation[1]	MWh Change	% Change	2016 EAF[2]	2016 NCF[3]	2015 EAF[2]	2015 NCF[3]
Gulf Coast – Texas	37,677	40,977	(3,301)	(8%)	88%	40%	88%	44%
Gulf Coast – South Central	13,423	16,701	(3,277)	(20%)	83%	36%	80%	45%
East	35,423	46,286	(10,863)	(23%)	80%	18%	84%	22%
West	4,369	4,542	(173)	(4%)	89%	8%	86%	8%
Renewables	3,883	3,790	93	2%	97%	40%	96%	37%
NRG Yield[4]	11,174	11,141	33	0%	98%	23%	98%	23%
Total	**105,950**	**123,438**	**(17,488)**	**(14%)**	**85%**	**24%**	**86%**	**27%**
Gulf Coast – Texas Nuclear	9,559	8,574	985	11%	95%	93%	85%	83%
Gulf Coast – Texas Coal	21,738	24,258	(2,520)	(10%)	85%	59%	89%	66%
Gulf Coast – South Central Coal	2,882	5,043	(2,161)	(43%)	72%	36%	75%	52%
East Coal	24,614	36,241	(11,627)	(32%)	71%	34%	83%	39%
Baseload	**58,794**	**74,116**	**(15,322)**	**(21%)**	**77%**	**47%**	**84%**	**50%**
Renewables Solar	1,690	1,508	182	12%	100%	51%	100%	49%
Renewables Wind	2,193	2,282	(89)	(4%)	96%	37%	96%	35%
NRG Yield Solar	1,225	1,213	12	1%	99%	31%	100%	30%
NRG Yield Wind	6,010	5,199	812	16%	97%	34%	96%	29%
Intermittent	**11,119**	**10,202**	**917**	**9%**	**97%**	**35%**	**97%**	**32%**
East Oil	1,432	1,584	(152)	(10%)	90%	3%	87%	3%
Gulf Coast – Texas Gas	6,379	8,145	(1,766)	(22%)	89%	14%	88%	18%
Gulf Coast – South Central Gas	10,541	11,658	(1,117)	(10%)	86%	37%	82%	43%
East Gas	9,377	8,461	916	11%	80%	15%	82%	14%
West Gas	4,369	4,542	(173)	(4%)	89%	8%	86%	8%
NRG Yield Conventional	1,697	2,487	(790)	(32%)	99%	10%	99%	15%
NRG Yield Thermal[4]	2,242	2,242	(1)	(0%)	95%	7%	92%	27%
Intermediate / Peaking	**36,037**	**39,120**	**(3,082)**	**(8%)**	**87%**	**13%**	**86%**	**14%**

[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 (SH) hours 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

Appendix: Finance

2016 O&M, SG&A & Maintenance Capex by Segment

($ Millions)	GENERATION	RETAIL	RENEWABLES	YIELD ("NYLD") Conventional & Thermal	YIELD ("NYLD") Renewables	YIELD ("NYLD") Corporate	NRG CORPORATE[1]	TOTAL CONSOLIDATED
GAAP Costs (Per 10K)								
Operations and Maintenance	1,638	248	121	80	94	-	(18)	2,163
Other Cost of Operations	223	93	20	33	32	-	2	403
SG&A	372	497	60	-	-	16	156	1,101
Total O&M and SG&A	**$ 2,233**	**$ 838**	**$ 201**	**$ 113**	**$ 126**	**$ 16**	**$ 140**	**$ 3,667**
Maintenance Capex	298	27	14	12	4	0	12	367
Total Costs	**$ 2,531**	**$ 865**	**$ 215**	**$ 125**	**$ 130**	**$ 16**	**$ 152**	**$ 4,034**
Less: Non-cash and deactivation costs								
Deactivation	(19)	-	-	-	-	-	(2)	(21)
Non-cash accretion for asset retirement obligations	(35)	-	(2)	(1)	(2)	-	(2)	(42)
Contract amortization for leases	49	-	-	-	0	-	-	49
Non-cash gains/(losses) on asset disposals	(21)	(1)	(1)	(3)	(3)	-	(5)	(34)
Total Non-cash and deactivation costs	**$ (27)**	**$ (1)**	**$ (4)**	**$ (3)**	**$ (5)**	**$ -**	**$ (9)**	**$ (48)**
Less: Other adjustments								
Intercompany revenues for services rendered	(5)	(2)	(24)				31	-
Operating leases	(133)							(133)
Nuclear asset (O&M,SG&A and Maintenance Capex)	(235)							(235)
Total Other Adjustents	**$ (373)**	**$ (2)**	**$ (24)**	**$ -**	**$ -**	**$ -**	**$ 31**	**$ (368)**
Total Excluded Costs & Other Adjustments	**$ (400)**	**$ (3)**	**$ (28)**	**$ (3)**	**$ (5)**	**$ -**	**$ 22**	**$ (417)**
Adjusted Costs incl Maint. Capex for Benchmarking	**$ 2,131**	**$ 862**	**$ 187**	**$ 122**	**$ 125**	**$ 16**	**$ 174**	**$ 3,617**

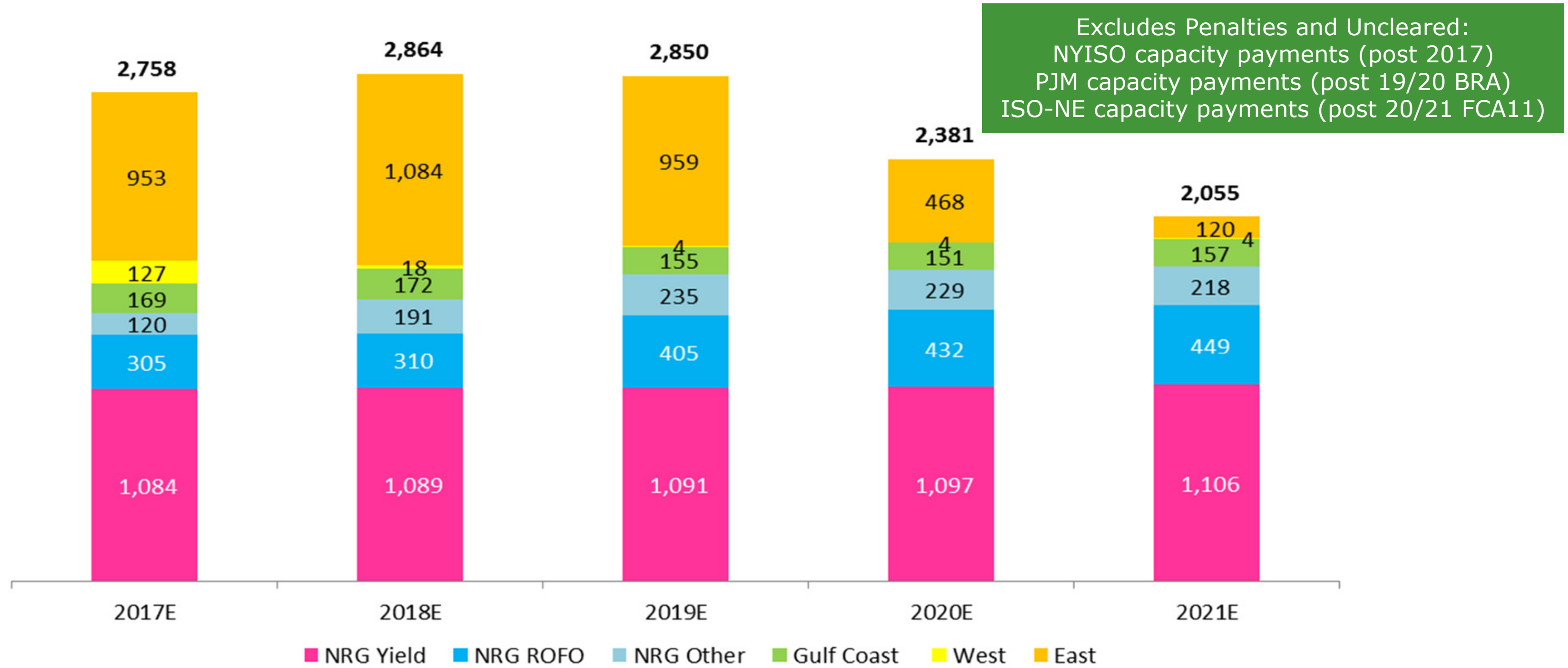
UNITS (Capacity / RCE)

	GENERATION	RETAIL	RENEWABLES	Conventional & Thermal	Renewables	Corporate	NRG CORPORATE[1]	TOTAL CONSOLIDATED
Net Reported MWs[2]	44,005		2,053	3,521	2,624		114	52,317
Less: Nuclear Asset	(1,136)							(1,136)
MWs for Benchmarking	**42,869**		**2,053**	**3,521**	**2,624**	**-**	**114**	**51,181**
Retail RCEs		**6,733**						**6,733**

[1] Includes Resi Solar and Consolidating Eliminations; [2] Includes total 900 MW of capacity for both Dunkirk which was mothballed (awaiting gas addition project) and Huntley deactivated during the year

Fixed Contracted and Capacity Revenue (Q4-2016)

($ millions)



Notes:

- East includes cleared capacity auction for PJM through May 2020, 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 Other includes renewable assets which are not part of ROFO and preferred resources projects
- NRG ROFO includes all wind, solar and conventional assets which are part of ROFO agreement including projects under construction (Carlsbad and Puente)
- NRG Yield includes contracted capacity, contracted energy and contracted steam revenues

2016 Net Capital Expenditures

($ millions)	Maintenance	Environmental	Growth	Total
Capital Expenditures				
Generation				
Gulf Coast	$ 157	7	8	**$ 172**
East	138	278	107	**523**
West	3	-	88	**91**
Retail	27	-	4	**31**
Renewables	14	-	308	**322**
NRG Yield	16	-	4	**20**
Corporate	12	-	73	**85**
Total Cash Capital Expenditures	**$ 367**	**$ 285**	**$ 592**	**$ 1,244**
Other Investments[1]	-	-	392	**392**
Project Funding, net of fees[2]	-	-	(312)	**(312)**
Total Capital Expenditures and Growth Investments, net	**$ 367**	**$ 285**	**$ 672**	**$ 1,324**

[1] Includes investments, restricted cash and $191 million for the acquisition of the SunEdison assets; [2] Includes net debt proceeds, cash grants and third-party contributions

Growth Investments and Capex, Net of Financing

($ millions)		2016A	2017E	2018E
NRG Level	Growth	564[2]	185	155
	Environmental	240	12	1
	Maintenance	220	211	215
GenOn	Growth Investments and Conversions	105	6	4
	Environmental	45	13	2
	Maintenance	118	72	93
Other[1]	Growth	3	2	-
	Environmental	-	-	-
	Maintenance	29	35	27
	Total:	**$1,324**	**$536**	**$497**

[1] Other includes NYLD, Ivanpah, and Agua Caliente; [2] Excludes contributions to nuclear decommissioning trust ($41 MM)

Generation Organizational Structure

NRG Energy, Inc. (47,216[1] MW)

Renewables (1,415 MW)

Solar
- Agua Caliente
- Community Solar
- Distributed Solar
- Four Brothers
- Georgia Solar
- Granite Mountain
- Guam
- Iron Springs
- Ivanpah
- Spanish Town

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

NRG Yield (2,582 MW)

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

Gulf Coast (14,863 MW)

- Bayou Cove
- Big Cajun I[4]
- Big Cajun II
- Cedar Bayou
- Cedar Bayou[3]
- Choctaw [4]
- Cottonwood
- Greens Bayou
- Gregory
- Limestone
- San Jacinto
- South Texas Project
- Sterlington[4]
- TH Wharton
- WA Parish

Other Conventional (22 MW)

- Petra Nova Cogen

West (6,085 MW)

- Ellwood
- Encina
- Etiwanda
- Long Beach
- Mandalay
- Midway Sunset
- Ormond Beach
- Saguaro
- San Diego Jet
- Sunrise
- Watson

Residential Solar (114 MW)

Other (749 MW)

- Doga
- Gladstone

East (21,386 MW)

- Arthur Kill
- Astoria
- Avon Lake
- Brunot Island
- Cheswick
- Conemaugh[2]
- Connecticut Jets
- Devon
- Fisk
- Hunterstown CC
- Huntley
- Indian River
- Joliet
- Keystone[2]
- Middletown
- Montville
- New Castle
- Niles
- Oswego
- Powerton
- Vienna
- Waukegan
- Will County

GenOn Americas Generation (7,907 MW)

- Pittsburg[5]
- Bowline
- Canal
- Martha's Vineyard

GenOn Mid-Atlantic (4,605 MW)

- Chalk Point
- Dickerson
- Morgantown

REMA (2,300 MW)

- Blossburg
- Gilbert
- Hamilton
- Hunterstown CT
- Mountain
- Orrtana
- Portland
- Sayreville
- Shawnee
- Shawville[6]
- Titus
- Tolna
- Warren

Pink marker: Part of GenOn Energy, Inc. Intercompany Revolver first lien package and subject to covenants of GenOn Unsecured Notes

LEGEND

- Separate Credit Facility (green dotted box)
- 75% interest sold to NRG Yield on November 3, 2015 (yellow box)
- Equity Investments (underlined)

[1] Capacity controlled by NRG as of 12/31/2016; [2] NRG and GenOn jointly own/lease portions of these plants; GenOn portion is subject to REMA liens; [3] Included as part of Peaker Finance Co; [4] Includes 275 MW related to Choctaw Unit 1 which is in forced outage and is expected to return to service in December 2017; [5] Pittsburg deactivated as of 1/1/2017 [6] Shawville gas conversion completed in Q4 2016

Consolidated Debt Structure

($ millions)
As of 12/31/2016

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

NRG Energy, Inc.

Revolver $2.5 BN due 2018/2021[1]	$	–
Senior notes due 2018-2027		5,449
Term loan due 2023		1,891
Tax exempt bonds due 2038-2045		455
Total	**$**	**7,795**

GenOn Energy, Inc.

Unsecured notes due 2017-2020	$	1,830
GenOn Hunterstown WG LP		54
GenOn Choctaw		42
Secured revolver from NRG Energy, Inc. (Intercompany)[2]		–

REMA

Capital lease	$	2
Operating leases[3]		–

GenOn Americas Generation

Senior unsecured notes due 2021 & 2031	$	695

GenOn Mid-Atlantic

Capital lease	$	–
Operating leases[3]		–

Conventional Financings

Peaker Bonds due 2019	$	0
Other non-recourse debt		7

Midwest Generation

Capacity Monetization/ Operating leases[4]	$	231

Agua Caliente

Project financing due 2037	$	849

Ivanpah

Project financing due 2016	$	39
Project financing due 2038		1,143

Other Renewables Financings

Project financings	$	556
Utah Portfolio[6]		287
Capital Lease		5

NRG Yield, Inc.

Senior convertible notes due 2019-2020	$	633

NRG Yield Operating LLC

Revolver $450 MM due 2019[5]	$	0
Green Bond notes		500
Senior Notes Due 2026		350

Conventional

Term loans due 2017 & 2023	$	1,169

Thermal

Senior secured notes due 2017-2025 and 2031	$	221

Renewable

Project financings	$	2,925

Note: Debt balances exclude discounts and premiums
[1] $1,319 MM LC's issued and $1,217 MM Revolver available at NRG
[2] $272 MM of LC's were issued and $228 MM of the Intercompany Revolver was available at GenOn
[3] The present value of lease payments (10% discount rate) for GenOn Mid-Atlantic operating lease is $583 MM, and the present value of lease payments (9.4% discount rate) for REMA operating lease is $346 MM
[4] 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.
[5] $60 MM of LC's were issued and $435 MM of the Revolver was available at NYLD
[6] Includes Four Brothers Holdings, Iron Springs Renewables, and Granite Mountain Renewables

Recourse / Non-Recourse Debt

($ millions)	12/31/2016	09/30/2016	06/30/2016	03/31/2016
Recourse Debt				
Term Loan Facility	$ 1,891	$ 1,895	$ 1,900	$ 1,961
Senior Notes	5,449	5,827	5,889	5,962
Tax Exempt Bonds	455	455	455	455
Recourse Debt Subtotal	**$ 7,795**	**$ 8,177**	**$ 8,244**	**$ 8,378**
Non-Recourse Debt				
Total NRG Yield[1,2]	$ 5,798	$ 5,733	$ 5,583	$ 5,634
GenOn Senior Notes	1,830	1,830	1,830	1,830
GenOn Americas Generation Notes	695	695	695	695
GenOn Other (including Capital Leases)	98	54	55	58
Renewables[2]	2,879	2,586	2,487	2,495
Conventional	238	257	277	85
Non-Recourse Debt and Capital Lease Subtotal	**$ 11,538**	**$ 11,155**	**$ 10,927**	**$ 10,797**
Total Debt	**$ 19,333**	**$ 19,332**	**$ 19,171**	**$ 19,175**

Note: Debt balances exclude discounts and premiums
[1] Includes convertible notes and project financings, including $189 MM related to Viento - NRG owns 25% of the project; [2] NRG Yield has been recast following the CVSR drop down on 09/01/2016

GenOn: Organizational Structure

($ millions)
MWs and Balances as of 12.31.16

Subject to restricted payments

GenOn Energy, Inc. (16,423 MW)	
7.875% Unsecured Notes, due 2017	$691
9.500% Unsecured Notes, due 2018	$649
9.875% Unsecured Notes, due 2020	$490
Secured Revolver from NRG Energy, Inc. (Intercompany)[1]	-
Total Debt[2]	**$1,830**
Consolidated Cash Balance	**$1,034**

GenOn Energy Holdings

REMA (2,300 MW)	
Capital Leases	$2
Operating Leases[4]	$346
Consolidated Cash Balance	**$100**

Asset	MW	ISO	Asset	MW	ISO
Blossburg	19	PJM	Portland	169	PJM
Conemaugh[3]	282	PJM	Sayreville	217	PJM
Gilbert	438	PJM	Shawnee	20	PJM
Hamilton	20	PJM	Shawville[7]	603	PJM
Hunterstown CT	60	PJM	Titus	31	PJM
Keystone[3]	285	PJM	Tolna	39	PJM
Mountain	40	PJM	Warren	57	PJM
Orrtanna	20	PJM			

GenOn Americas Generation (7,907 MW) (formerly "MAGI")	
8.500% Senior Unsecured Notes, due 2021	$366
9.125% Senior Unsecured Notes, due 2031	$329
Total Debt[5]	**$695**
Consolidated Cash Balance (includes "MIRMA")	**$471**

GenOn Mid-Atlantic (4,605 MW) ("MIRMA")	
Operating Leases[4]	$583
Consolidated Cash Balance	**$471**

Asset	MW	ISO
Chalk Point	2,279	PJM
Dickerson	849	PJM
Morgantown	1,477	PJM

Rest of GenOn Americas (3,302 MW)
No Debt

Asset	MW	ISO
Bowline	1,147	NYISO
Canal Units 1-2	1,112	ISONE
Martha's Vineyard	14	ISONE
Pittsburg[8]	1,029	CAISO

Rest of GenOn Inc (6,216 MW)	
Vendor Financing (Hunterstown)[6]	$54
Vendor Financing (Choctaw)[6]	$42

Asset	MW	ISO	Asset	MW	ISO
Avon Lake	659	PJM	Hunterstown CCGT	810	PJM
Brunot Island	259	PJM	Mandalay	560	CAISO
Cheswick	565	PJM	New Castle	328	PJM
Choctaw[9]	800	SERC	Niles	25	PJM
Ellwood	54	CAISO	Ormond Beach	1,516	CAISO
Etiwanda	640	CAISO			

[1]$272MM of LC's were issued and $228MM of the Intercompany Revolver was available; [2]Excludes premium of $81MM on GenOn debt; [3]REMA jointly leases portions of these plants; GenOn portion is subject to REMA liens; [4]The present value of the lease payments (10% discount rate at GenMA; 9.4% at REMA); [5]Excludes premiums of $50MM; [6] GAAP classification for portion of LTSA payments; [7]Gas conversion completed in Q4 2016; [8] Pittsburg deactivated as of 1/1/2017 [9] Includes 275 MW related to Choctaw Unit 1 which is in forced outage and is expected to return to service in December 2017

Schedule of Debt Maturities

$ in millions as of December 31, 2016 Issuance	Maturity Year	NRG Recourse	Nonrecourse to NRG GenOn	Nonrecourse to NRG Yield
7.875% GenOn Senior Notes	**2017**	$ -	**$ 691**	$ -
7.625% NRG Senior Notes	2018	398	-	-
9.50% GenOn Senior Notes	2018	-	649	-
	2018 Total	**398**	**649**	**-**
3.5% NRG Yield, Inc. Convertible Notes	**2019**	**-**	**-**	**345**
9.875% GenOn Senior Notes	2020	-	490	-
3.25% NRG Yield, Inc. Convertible Notes	2020	-	-	288
	2020 Total	**-**	**490**	**288**
7.875% NRG Senior Notes	2021	206	-	-
8.50% GenOn Americas Generation Senior Notes	2021	-	366	-
	2021 Total	**206**	**366**	**-**
4.750% Tax Exempt Bonds due 2022	2022	54	-	-
6.25% NRG Senior Notes	2022	992	-	-
	2022 Total	**1,046**	**-**	**-**
NRG Term Loan	2023	1,891		
6.625% NRG Senior Notes	2023	869	-	-
	2023 Total	**2,760**	**-**	**-**
6.25% NRG Senior Notes	2024	734	-	-
5.375% Yield Operating LLC Senior Notes	2024	-		500
	2024 Total	**734**	**-**	**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**	**-**	
9.125% GenOn Americas Generation Senior Notes	**2031**	**-**	**329**	**-**
6.0% Tax Exempt Bonds	**2040**	**57**	**-**	**-**
4.750% 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	**7,795**	**2,525**	**1,483**
Non-Recourse Project Debt and Capital Leases[1]	**Various**		**98**	**4,315**
	Total Debt		**$ 2,623**	**$ 5,798**

Note: Debt balances exclude discounts and premiums
[1] Includes project-level debt and capital leases that are non-recourse to NRG, GenOn and Yield

Appendix:
Reg. G Schedules

Reg. G: Full Year 2016 Free Cash Flow before Growth

($ millions)		12/31/2016
Adjusted EBITDAR	**$**	**3,390**
Less: GenOn & EME operating lease expense		(133)
Adjusted EBITDA	**$**	**3,257**
Interest payments		(1,107)
Debt Extinguishment Cash Costs		(120)
Income tax		(27)
Collateral / working capital / other		69
Cash Flow from Operations	**$**	**2,072**
Reclassifying of net receipts (payments) for settlement of acquired derivatives that include financing elements		151
Merger, integration and cost-to-achieve expenses[1]		40
Sale of Potrero land		74
Return of capital from equity investments[2]		17
Collateral		(365)
Adjusted Cash Flow from Operations	**$**	**1,989**
Maintenance capital expenditures, net [3]		(330)
Environmental capital expenditures, net		(285)
Preferred dividends		(2)
Distributions to non-controlling interests [4]		(163)
Consolidated Free Cash Flow before Growth	**$**	**1,209**
Less: FCFbG at Non-Guarantor Subsidiaries[5]		(516)
NRG-Level Free Cash Flow before Growth	**$**	**693**

[1] Cost-to-achieve expenses associated with the $150 MM savings announced on September 2015 call [2] Represents cash distributions to NRG from equity investments
[3] Includes insurance proceeds of $37 MM [4] Excludes $87MM cash distribution of debt proceeds made by Capistrano to non-controlling interests [5] Reflects impact from GenOn, 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)	2017 Guidance
Generation and Renewables	$1,135 - $1,255
Retail Mass	700 – 780
NRG Yield	865
Adjusted EBITDA	**$2,700 - $2,900**
Interest payments	(1,065)
Debt Extinguishment Cash Cost	--
Income tax	(40)
Working capital / other	(240)
Adjusted Cash Flow from Operations	**$1,355 - $1,555**
Maintenance capital expenditures, net	(310) - (340)
Environmental capital expenditures, net	(10) - (30)
Preferred dividends	--
Distributions to non-controlling interests[1]	(185) – (205)
Consolidated Free Cash Flow before Growth	**$800 - $1,000**
Less: FCFbG at Non-Guarantor Subsidiaries[2]	(100)
NRG-Level Free Cash Flow before Growth	**$700 - $900**

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

Reg. G

Appendix Table A-2: Fourth 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)	Generation	Retail	Renewables	NRG Yield	Corp/Elim	Total
Net (loss)/income	(889)	316	(204)	(126)	(152)	(1,055)
Plus:						
Interest expense, net	9	-	22	61	124	216
Income tax	1	-	(6)	(26)	(48)	(79)
Loss on debt extinguishment	-	-	-	-	23	23
Depreciation and amortization	224	28	47	73	16	388
ARO expense	13	-	1	1	1	16
Amortization of contracts	(4)	1	-	17	-	14
Amortization of leases	(12)	-	-	-	-	(12)
EBITDA	**(658)**	**345**	**(140)**	**-**	**(36)**	**(489)**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	6	-	23	21	(36)	14
Reorganization costs	-	-	-	-	3	3
Deactivation costs	4	-	-	-	1	5
Other non recurring charges	1	2	1	3	(1)	6
Impairment losses	561	1	30	183	20	795
Impairment losses on investments	-	-	106	-	15	121
Mark-to-Market (MtM) losses/(gains) on economic hedges	246	(214)	6	-	(1)	37
Adjusted EBITDA	**160**	**134**	**26**	**207**	**(35)**	**492**

Reg. G

Appendix Table A-3: Fourth Quarter 2015 Adjusted EBITDA Reconciliation by Operating Segment
The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to net (loss)/income

($ millions)	Generation	Retail	Renewables	NRG Yield	Corp/Elim	Total
Net (loss)/income	(4,690)	161	(18)	12	(1,823)	(6,358)
Plus:						
Interest expense, net	17	-	19	63	171	270
Income tax	(3)	-	(5)	4	1,389	1,385
Loss on debt extinguishment	-	-	-	-	(84)	(84)
Depreciation and amortization	223	33	46	75	16	393
ARO expense	7	-	-	-	1	8
Amortization of contracts	(4)	2	-	14	-	12
Amortization of leases	(12)	-	-	-	-	(12)
EBITDA	**(4,462)**	**196**	**42**	**168**	**(330)**	**(4,386)**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	4	-	(32)	15	38	25
Acquisition-related transaction & integration costs	-	-	-	-	2	2
Reorganization costs	3	3	6	-	6	18
Deactivation costs	3	-	-	-	-	3
Other non recurring charges	4	(1)	2	3	5	13
Impairment losses	4,605	-	8	-	154	4,767
Impairment losses on investments	14	-	-	-	42	56
Mark- to- Market (MtM) losses/(gains) on economic hedges	129	(49)	1	3	-	84
Adjusted EBITDA	**300**	**149**	**27**	**189**	**(83)**	**582**

Reg. G

Appendix Table A-4: Full Year 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)	Generation	Retail	Renewables	NRG Yield	Corp/Elim	Total
Net (loss)/income	(507)	1,045	(306)	(15)	(1,108)	(891)
Plus:						
Interest expense, net	65	-	107	273	601	1,046
Income tax	(1)	1	(20)	(1)	37	16
Loss on debt extinguishment	-	-	-	-	142	142
Depreciation and amortization	702	115	190	297	63	1,367
ARO expense	35	-	2	3	2	42
Amortization of contracts	(18)	7	1	74	(4)	60
Amortization of leases	(49)	-	-	-	-	(49)
EBITDA	**227**	**1,168**	**(26)**	**631**	**(267)**	**1,733**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	30	-	42	79	(45)	106
Acquisition-related transaction & integration costs	-	-	-	-	7	7
Reorganization costs	-	5	3	-	21	29
Deactivation costs	19	-	-	-	2	21
(Gain)/loss on sale of business	(223)	-	-	-	79	(144)
Other non recurring charges	21	1	1	6	5	34
Impairment losses	645	1	56	183	33	918
Impairment losses on investments	142	-	105	-	21	268
Mark- to- Market (MtM) losses/(gains) on economic hedges	644	(364)	6	-	(1)	285
Adjusted EBITDA	**1,505**	**811**	**187**	**899**	**(145)**	**3,257**

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Appendix Table A-5: Full Year 2015 Adjusted EBITDA Reconciliation by Operating Segment

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

($ millions)	Generation	Retail	Renewables	NRG Yield	Corp/Elim	Total
Net (loss)/income	(4,446)	624	(92)	65	(2,587)	(6,436)
Plus:						
Interest expense, net	68	1	80	262	704	1,115
Income tax	-	1	(18)	12	1,347	1,342
Loss/(gain) on debt extinguishment	-	-	-	9	(84)	(75)
Depreciation and amortization	896	133	181	297	59	1,566
ARO expense	32	-	-	2	1	35
Amortization of contracts	(10)	6	1	54	-	51
Amortization of leases	(50)	-	-	-	-	(50)
EBITDA	**(3,510)**	**765**	**152**	**701**	**(560)**	**(2,452)**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	27	-	(20)	49	34	90
Acquisition-related transaction & integration costs	-	1	-	3	6	10
Reorganization costs	3	3	6	-	6	18
Deactivation costs	11	-	-	-	-	11
Gain on sale of business	-	-	(3)	-	-	(3)
Other non recurring charges	20	(12)	7	3	16	34
Impairment losses	4,827	36	13	-	154	5,030
Impairment losses on investments	14	-	-	-	42	56
Mark –to- Market (MtM) losses on economic hedges	367	-	3	2	-	372
Adjusted EBITDA	**1,759**	**793**	**158**	**758**	**(302)**	**3,166**

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Appendix Table A-6: Fourth Quarter 2016 Regional Adjusted EBITDA Reconciliation for Generation
The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to net (loss)/income

($ millions)	East	Gulf Coast	West	Other	Total
Net (loss)/income	(123)	(662)	(92)	(12)	(889)
Plus:					
Interest expense, net	9	-	-	-	9
Income tax	-	-	-	1	1
Depreciation and amortization	56	157	11	-	224
ARO expense	2	3	8	-	13
Amortization of contracts	(5)	2	(1)	-	(4)
Amortization of leases	(11)	(1)	-	-	(12)
EBITDA	**(72)**	**(501)**	**(74)**	**(11)**	**(658)**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	-	(2)	4	4	6
Deactivation costs	3	-	1	-	4
Other non recurring charges	3	1	(1)	(2)	1
Impairment losses	118	358	85	-	561
Mark-to- Market (MtM) losses on economic hedges	5	236	5	-	246
Adjusted EBITDA	**57**	**92**	**20**	**(9)**	**160**

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Appendix Table A-7: Fourth Quarter 2015 Regional Adjusted EBITDA Reconciliation for Generation
The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to net loss

($ millions)	East	Gulf Coast	West	Other	Total
Net loss	(164)	(4,488)	(25)	(13)	(4,690)
Plus:					
Interest expense, net	16	-	-	1	17
Income tax	-	-	-	(3)	(3)
Depreciation and amortization	92	119	11	1	223
ARO expense	4	1	2	-	7
Amortization of contracts	(6)	-	2	-	(4)
Amortization of leases	(12)	(1)	-	1	(12)
EBITDA	**(70)**	**(4,369)**	**(10)**	**(13)**	**(4,462)**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	-	(1)	2	3	4
Reorganization costs	-	3	-	-	3
Deactivation costs	3	-	-	-	3
Other non recurring charges	15	(19)	6	2	4
Impairment losses	214	4,383	8	-	4,605
Impairment losses on investments	-	14	-	-	14
Mark- to- Market (MtM) losses on economic hedges	23	103	3	-	129
Adjusted EBITDA	**185**	**114**	**9**	**(8)**	**300**

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Appendix Table A-8: Full Year 2016 Regional Adjusted EBITDA Reconciliation for Generation
The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to net income/(loss)

($ millions)	**East**	**Gulf Coast**	**West**	**Other**	**Total**
Net income/(loss)	373	(911)	(19)	50	(507)
Plus:					
Interest expense, net	65	1	-	(1)	65
Income tax	-	(2)	-	1	(1)
Depreciation and amortization	212	432	57	1	702
ARO expense	7	11	17	-	35
Amortization of contracts	(22)	6	(4)	2	(18)
Amortization of leases	(47)	(2)	-	-	(49)
EBITDA	**588**	**(465)**	**51**	**53**	**227**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	-	3	11	16	30
Deactivation costs	18	-	1	-	19
Gain on sale of assets	(217)	-	(6)	-	(223)
Other non recurring charges	7	16	(1)	(1)	21
Impairment losses	135	367	143	-	645
Impairment losses on investments	-	142	-	-	142
Mark –to- Market (MtM) losses on economic hedges	180	444	20	-	644
Adjusted EBITDA	**711**	**507**	**219**	**68**	**1,505**

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Appendix Table A-9: Full Year 2015 Regional Adjusted EBITDA Reconciliation for Generation
The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to net income/(loss)

($ millions)	**East**	**Gulf Coast**	**West**	**Other**	**Total**
Net income /(loss)	17	(4,439)	5	(29)	(4,446)
Plus:					
Interest expense, net	68	-	1	(1)	68
Depreciation and amortization	299	546	51	-	896
ARO expense	14	6	12	-	32
Amortization of contracts	(19)	5	2	2	(10)
Amortization of leases	(47)	(3)	-	-	(50)
EBITDA	**332**	**(3,885)**	**71**	**(28)**	**(3,510)**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	-	3	8	16	27
Reorganization costs	-	3	-	-	3
Deactivation costs	8	-	3	-	11
Other non recurring charges	24	(1)	(1)	(2)	20
Impairment losses	436	4,383	8	-	4,827
Impairment losses on investments	-	14	-	-	14
Mark –to- Market (MtM) losses on economic hedges	276	83	8	-	367
Adjusted EBITDA	**1,076**	**600**	**97**	**(14)**	**1,759**

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Appendix Table A-10: Full Year 2016 Adjusted EBITDA Reconciliation for GenOn Energy, Inc., ROFO/Other[1] and NRG Yield

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

($ millions)	Genon	ROFO/Other	NRG Yield
Net income/(loss)	**81**	**(477)**	**(15)**
Plus:			
Income tax	11	(11)	(1)
Interest expense, net	171	115	272
Depreciation, Amortization, Contract Amortization, and ARO Expense	137	246	375
EBITDA	**400**	**(127)**	**631**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	-	45	78
Deactivation costs	4	(0)	-
Merger & transaction costs	-	-	1
Gain on sale of business	(223)	-	-
Other Non-Recurring Charges	2	1	2
Reorganization Costs	0	18	-
Asset Write-Offs	3	6	4
Impairments	214	190	183
Mark to market (MtM) losses on economic hedges	151	45	-
Plus: Operating lease expense	112	21	-
Adjusted EBITDAR	**663**	**199**	**899**
Less: Operating lease expense	(112)	(21)	-
Adjusted EBITDA	**551**	**178**	**899**

[1] Includes Aqua Caliente, Ivanpah, Midwest Generation, Capistrano, and other assets

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Appendix Table A-11: Expected Full Year 2017 Adjusted EBITDA Reconciliation for GenOn Energy, Inc., ROFO/Other[1] and NRG Yield

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

($ millions)	Genon	ROFO/Other	NRG Yield
Net (loss)/income	**(147)**	**84**	**110**
Plus:			
Income tax	-	-	20
Interest expense, net	186	68	310
Depreciation, Amortization, Contract Amortization, and ARO Expense	133	227	355
EBITDA	**173**	**379**	**795**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	-	-	70
Deactivation costs	22	-	-
Reorganization Costs	-	-	-
Mark to market (MtM) losses on economic hedges	(50)	21	-
Plus: Operating lease expense	112	21	-
Adjusted EBITDAR	**257**	**421**	**865**
Less: Operating lease expense	(112)	(21)	-
Adjusted EBITDA	**145**	**400**	**865**

[1] Includes Aqua Caliente, Ivanpah, Midwest Generation, Capistrano, and other assets

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Appendix Table A-12: 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	**145**	**1,265**	**1,410**
Interest payments	(240)	(350)	(590)
Collateral / working capital / other	(126)	(164)	(290)
Cash Flow from Operations	**(221)**	**751**	**530**
Sale of Potrero land	-	-	-
Return of capital from equity investments[2]	-	-	-
Collateral	-	-	-
Adjusted Cash Flow from Operations	**(221)**	**751**	**530**
Maintenance capital expenditures, net	(72)	(35)	(107)
Environmental capital expenditures, net	(7)	-	(7)
Distributions to NRG	-	(142)	(142)
Distributions to non-controlling interests	-	(174)	(174)
Free Cash Flow before Growth	**(300)**	**400**	**100**

[1] Includes NRG Yield and other assets (primarily Aqua Caliente, Ivanpah, and Capistrano); [2] Represents cash distributions from equity investments

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Appendix Table A-13: 2017 Adjusted EBITDA Guidance Reconciliation: The following table summarizes the calculation of Adjusted EBITDA providing reconciliation to net income:

	2017 Adjusted EBITDA Guidance	
($ millions)	**Low**	**High**
GAAP Net Income [1]	60	260
Income tax	80	80
Interest Expense and Debt Extinguishment Costs	1,155	1,155
Depreciation, Amortization, Contract Amortization and ARO Expense	1,235	1,235
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	110	110
Other Costs [2]	60	60
Adjusted EBITDA	**2,700**	**2,900**

[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, reorganization costs, asset write-offs, impairments and evgo Califonia settlement

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Appendix Table A-14: Full Year 2013 & 2014 Adjusted EBITDA Reconciliation – Retail
The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to net income/(loss)

($ millions)	**2013**	**2014**
Net income/(loss)	548	(24)
Plus:		
Interest expense, net	3	2
Income tax	0	1
Loss on debt extinguishment	-	-
Depreciation, amortization, and ARO expense	146	134
Amortization of contracts	55	4
Amortization of leases	-	-
EBITDA	**752**	**117**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	-	-
Acquisition-related transaction & integration costs	0	3
Reorganization costs	-	-
Deactivation costs	-	-
(Gain)/loss on sale of business	-	-
Other non recurring charges	3	5
Impairment losses	0	-
Impairment losses on investments	-	-
Mark- to- Market (MtM) losses/(gains) on economic hedges	(150)	507
Adjusted EBITDA	**605**	**632**

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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.