NRG Energy Inc.

Third Quarter 2016 Earnings Presentation

November 4, 2016

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, our ability to obtain federal loan guarantees, 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 November 4, 2016. 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

Key Highlights

Delivering on 2016 Financial Guidance: Narrowing and increasing 2016 EBITDA guidance; initiating 2017 guidance

Executing on Renewables Strategy: Strengthening partnership with NRG Yield through organic growth and SunEdison transaction

On Track to Achieve Deleveraging Targets: Continued capital discipline across organization

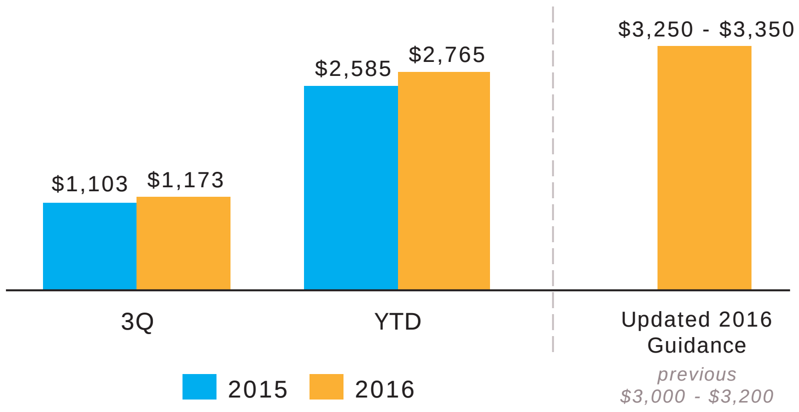
Q3 Business Update

Operational Excellence Drives 3Q Results: Key Objectives On Track

- ☑ **Delivered Strong Results:** Continued best-in-class operations throughout integrated platform. Improved safety record to top decile
- ☑ **Executing on Deleveraging Program:** Reduced corporate-level debt by ~$1 Bn since 3Q15 and extended $6.2 Bn beyond 2020
- ☑ **Growing Renewable Portfolio:** Acquiring 1.5 GW_{ac} SunEdison (SUNE) portfolio with opportunity for quick capital recycling and low-cost growth
- ☑ **Strengthening NRG Yield:** Renewable asset acquisitions (SUNE); completed drop down of CVSR; initiated UPMC thermal project
- ☑ **Streamlining the Organization:** fornrg cost-savings initiative on track to achieve $400 MM through 2017

Increasing 2016 EBITDA Guidance and Introducing 2017 Guidance

Adjusted EBITDA ($MM)



($ millions)	2017E Guidance
Adjusted EBITDA	$2,700 - $2,900
Free Cash Flow Before Growth	$800 - $1,000

Results and Increased Guidance Underpinned by Continued Strength of Integrated Platform

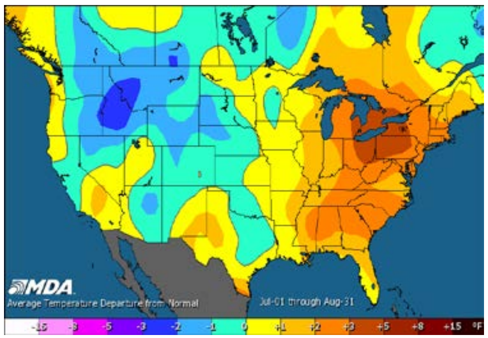
Summer 2016 Review

Mild Weather in ERCOT While Above Average in East

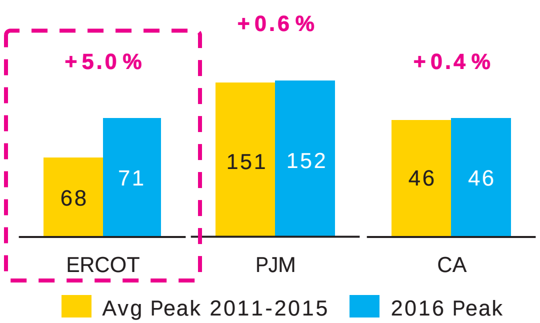
Power Prices Settled as Expected, Except in ERCOT

Forward Prices Relatively Stable Through Quarter

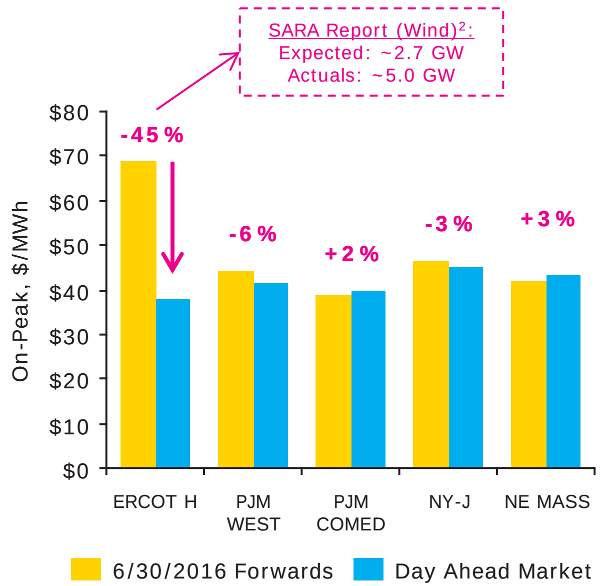
Jul-Aug 2016 Temps Compared to 10-Year Normal



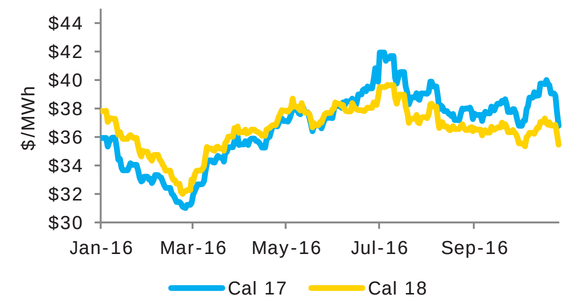
Peak Load Comparison (GW)[1]



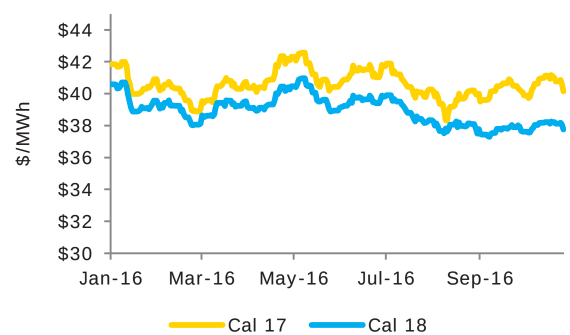
Summer Forwards Versus Actuals July - August



ERCOT-Houston On-Peak[3]



PJM West On-Peak[3]

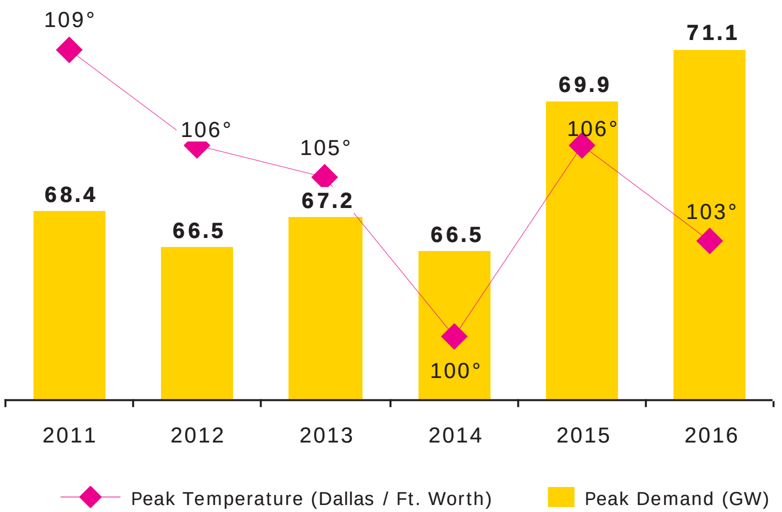


Summer Prices in Texas Impacted by Mild Weather and Wind Outperformance; Forward Prices Largely Stable During Quarter

[1] ERCOT, PJM ISO, CAISO data; [2] SARA report estimate for peak hour of peak day; [3] as of 10/28/16

Market Outlook

ERCOT: All-time Peak Load Reached Without Record Temperatures[1]



- Continued strong demand growth: 1.4% weather-normalized growth year-to-date
- Persistent low wholesale prices puts existing generation at risk
- PUCT focus turning back to ORDC reform from EFH restructuring

East: Constructive PJM Capacity Market in 20/21

- **Competitive Markets:** Successfully opposed subsidies in OH and taking action in NY ZEC and IL
- **Energy Market:** Capacity Performance incentives and new builds continue to put pressure on scarcity pricing
- **Capacity Market:** Constructive outlook given retirements and 100% CP requirement for 20/21 BRA

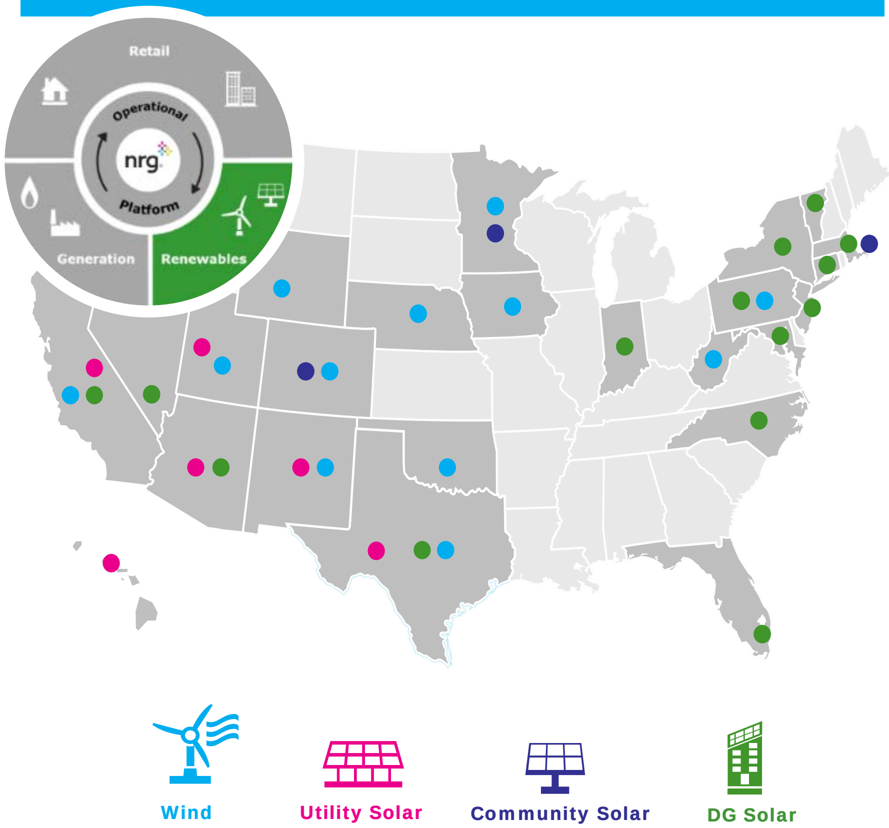
Market Driver		Outlook
100% CP Requirement	↑	➢ 100% CP in 20/21 adds risk to the ~17 GW of generation that cleared as base capacity in 19/20
Demand-side Participation	↑	➢ Enhanced seasonal requirements add risk to ~10 GW of demand response and energy efficiency that cleared as base in 19/20
Imports	↑	➢ Expected increasing requirements and limitations for imports
Stagnant Load	↓	➢ Updated mid-year load forecast slightly lower than Jan-2016 forecast (for PY19/20)

Outlook for ERCOT Fundamentals and PJM Capacity Market Remains Strong

[1] ERCOT, NOAA

NRG Renewables Business

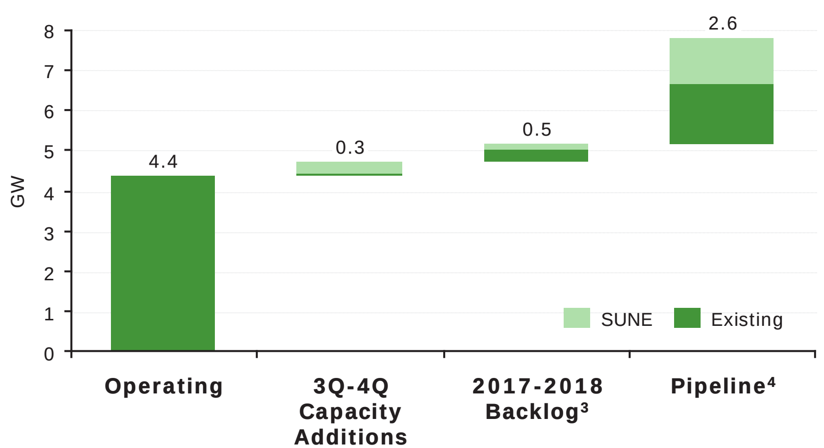
A Leading Renewable Energy Platform[1] with 4.4 GW of Renewable Generation…



…and with a Unique Competitive Advantage in a Quickly Growing Sector

- ☑ Best-in-Class Operations and Asset Management
- ☑ Fully-Integrated, End to End Platform
- ☑ Quick Capital Replenishment through NRG Yield
- ☑ Ability to Leverage Retail C&I / Utility Customer Base
- ☑ Repowering Opportunities at Existing Sites

Operating Portfolio + Pipeline[2]



NRG Continues to Execute its Renewables Strategy at Significant Scale and with a Substantial Pipeline for Future Growth

[1] 4.4 GW at NRG Consolidated, of which 2.6 GW is at NYLD; [2] MW amounts in AC; [3] Backlog is defined as projects that are under construction for 2017 delivery, contracted, or awarded, and represents a higher level of execution certainty; [4] Pipeline is defined as projects that range from identified lead to shortlisted with an offtake, and represents a lower level of execution certainty

SunEdison Transactions

SUNE Asset Acquisitions Enhance NRG Renewable Position Today and Into the Future…

Utility-Scale Assets[1] (1.5 GW_{ac})

$129 MM Initial Price + $59 MM Earn-Out Potential

- **Operational**: 265 MW[2]
- **Backlog** (2017-18): 154 MW[3]
- **Pipeline** (2018+): 1.1 GW

Distributed Generation Assets (29 MW_{ac})

$68 MM Price

- **Mechanically Complete**: 17 MW
- **Notice to Proceed**: 12 MW

…and Provide the Opportunity for Quick Capital Return and a Low-Cost Development Option

☑ **Quick Capital Replenishment**

- Over 85% of purchase price justified with value from operational assets
  - Expect mid-teens levered CAFD yields

☑ **Low-Cost Pipeline Option**

- Remaining value attributed to 1.2 GW backlog and pipeline
- $59 MM earn-out transaction structure mitigates backlog and pipeline conversion risk

☑ **Strengthening NRG Yield Partnership**

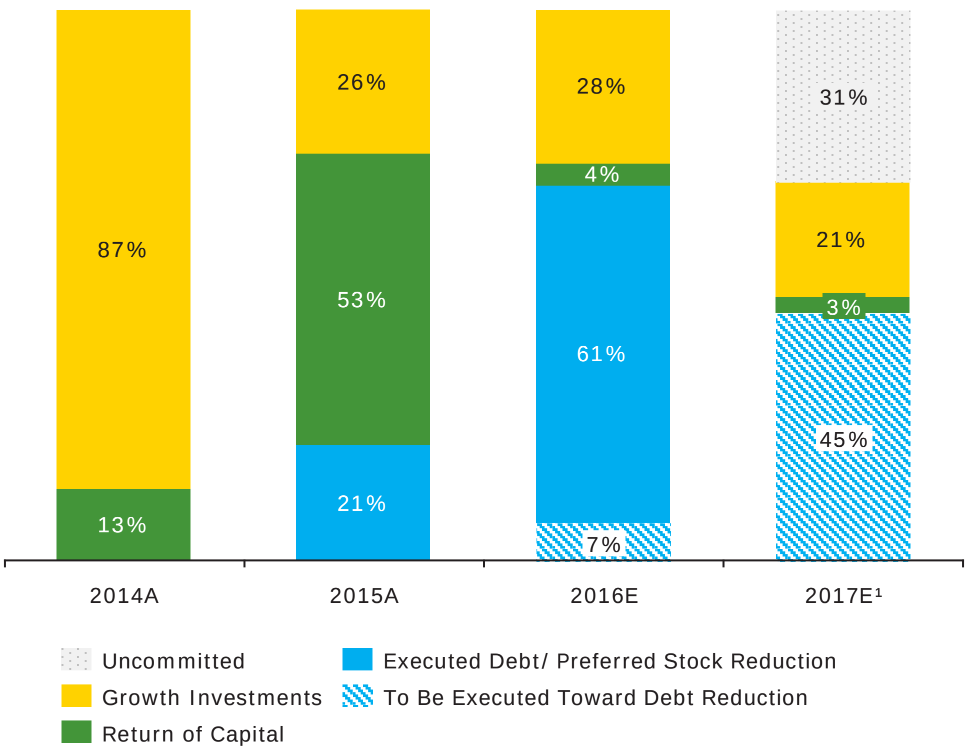
- DG assets to be placed in DG partnership with NRG Yield throughout 2017
  - Expect high-teens levered CAFD yields

Uniquely Positioned to Capture Value from Acquisitions: NRG Scale Enables Portfolio Bid and Strategic Partnership with NRG Yield Enables Quick Return of Capital

[1] 3Q16E Operational: Utah Assets – Four Brothers (160 MW_{ac}), Three Cedars (105 MW_{ac}); [2] Assumes 50% ownership of Utah projects reflecting NRG's net interest based on cash to be distributed in tax equity partnership with Dominion; [3] 2017-18 Backlog: Texas Solar (154 MW)

2017 Capital Allocation Assessment

NRG Capital Allocation Mix



Options for Capital Allocation

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

Continued Capital Discipline in 2017 as Current Deleveraging Program is Nearing Completion

[1] Includes approximate $200 MM expected proceeds from the monetization of yield eligible projects

Financial Update

Financial Summary

($ millions)	September 30, 2016	
	Three Months Ended	Nine Months Ended
Generation & Renewables[1]	$661	$1,444
Retail Mass	266	629
NRG Yield	246	692
Adjusted EBITDA	**$1,173**	**$2,765**
Free Cash Flow before Growth	**$911**	**$1,131**

Increasing and Narrowing 2016 Adjusted EBITDA Guidance:

$3,250 - $3,350
(previously $3,000-3,200)

- Completed $1 Bn[2] corporate debt reduction:
  - $777 MM retired YTD through November 3, 2016; additional $246 MM retired in 2015
  - Annual interest savings of $78 MM achieved plus $10 MM in annual preferred dividend savings
- Closed CVSR Drop Down: $180 MM cash consideration[3]

[1] Includes Corporate Segment; [2] Comprised of 2015 corporate debt reduction of $246 MM (cash cost of $226 MM), YTD September 2016 of $399 MM (cash cost of $478 MM), and $186 MM (cash cost of $200 MM) and $193 MM (cash cost of $200 MM) of debt reduction completed on October 19 and November 3, 2016, respectively; [3] Comprised of NRG portion of project-level net financing proceeds of $101.5 MM (closed July'16) and NYLD cash proceeds from Drop Down of $78.5 MM (closed in 3Q16)

Introducing 2017 Guidance

($ millions)	Increased and Narrowed **2016 Revised Guidance** *(previous guidance)*	**2017 Guidance**
Generation & Renewables[1,2]	$1,640-1,690 *$1,545-1,670*	$1,135 – $1,255[3]
Retail Mass	725-775 650-725	700 – 780
NRG Yield[2]	885 805	865
Adjusted EBITDA Guidance	**$3,250-3,350** *$3,000-3,200*	**$2,700 - $2,900[3]**
Impact of GenOn hedge monetization in 2016	*120*	*(100)*

Consolidated Free Cash Flow before Growth ("FCFbG")	**$1,100 - $1,200** *$1,000 - $1,200*	**$800 - $1,000**
Adjustments (mid-point):		
Less: FCFbG at GenOn	35	(300)
Less: FCFbG at NRG Yield and Other Non-Guarantor Subsidiaries, net of distributions[4]	385	400
NRG-Level FCFbG	**$680 - $780** *$750 - $950*	**$700 - $900**

FCFbG (Consolidated and NRG-Level) include $120 MM debt extinguishment costs for the debt reduction and extensions achieved

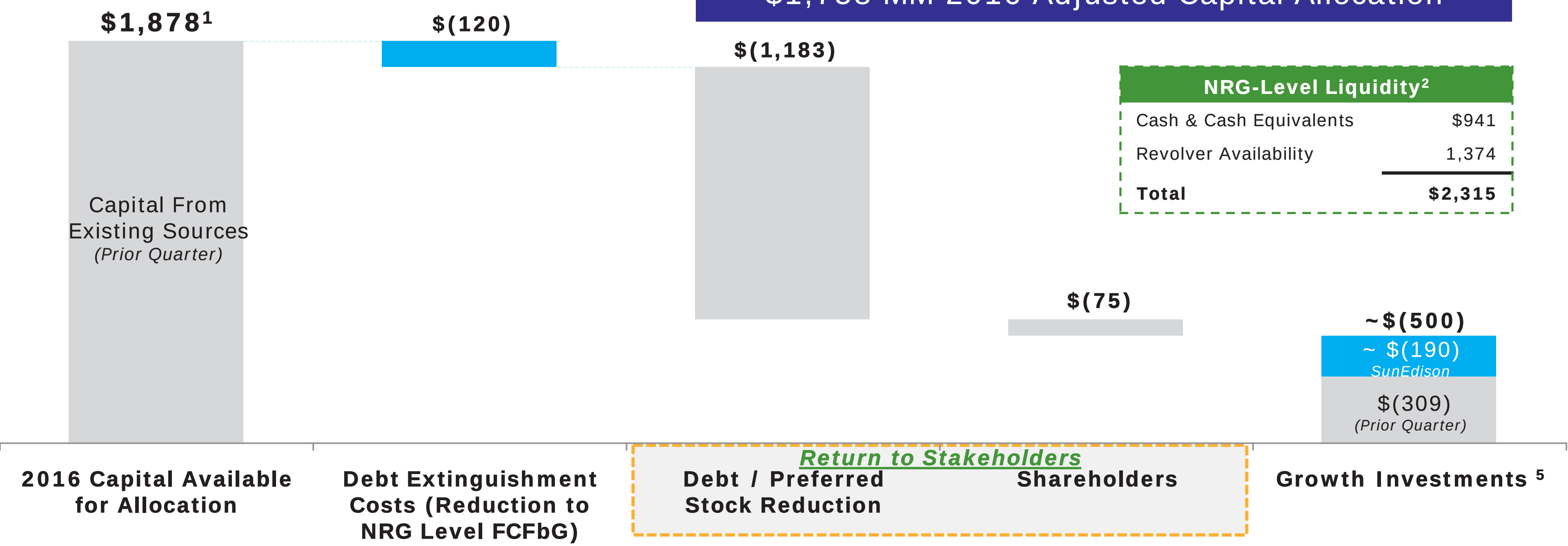
Consistently Delivering on NRG-Level FCFbG in Challenging Commodity Markets

[1] Includes Corporate Segment; [2] In accordance with GAAP, restated to reflect full impact of CVSR dropdown to NYLD of ~$40 MM; [3] Guidance ranges include the impact of a reduction of ~$100 MM as a result of hedges monetized in 2016 at GenOn; [4] Represents FCFbG net of distributions to NRG Corp and to non-controlling interests; primarily Ivanpah, Agua Caliente, and Capistrano

2016 NRG-Level Capital Allocation

($ millions)

$1,758 MM 2016 Adjusted Capital Allocation



NRG-Level Liquidity[2]

Cash & Cash Equivalents	$941
Revolver Availability	1,374
Total	**$2,315**

✓	Corp Debt Amortization	$20
✓	Repurchased thru 9/30/16[3]	$380
✓	2018/21 Repurchases[4]	$378
✓	Refinancing Fees	$59
✓	Preferred Stock Redeemed	$226
	Reserved: 2018 Maturity	$120

Common Dividends

1st Quarter	$46
2nd - 4th Quarter	$29

2018 Reserve to be replenished to $400 MM in 2017 via NRG-Level FCFbG/Dropdowns

✓ = completed

$1.0 Bn Corporate Debt Reduction completed; 2018 Maturity Reserve to be augmented with 2017 capital, including potential drop down of SunEdison assets

[1] Refer to slide 10 of 2Q16 earnings call presentation. Capital from Existing Sources includes: 2015 remaining capital of $513 MM plus $850 MM representing prior mid-point of 2016 NRG Level FCFbG guidance, expected NYLD Resi Solar & DG Drop Down proceeds of $125 MM, $253 MM of proceeds raised in April 2016 from the monetization of certain capacity revenues through 2019 at MidWest Generation (MWG), less the impact of 2016 capacity revenue sold of $43 MM, and CVSR project-level net financing and drop down proceeds totaling $180 MM (closed in 3Q16); [2] Includes $250 MM cash held at MWG which can be distributed to NRG Corporate with no restrictions; revolver availability represents $2.5 Bn revolving credit facility, less $1.2 Bn of letters of credit issued as of 09/30/2016; [3] Completed YTD September, 30 2016; [4] Comprised of $186 MM and $192 MM of debt reduction completed on October 19 and November 3, 2016, respectively; [5] Net of financing

NRG's Capital Structure & Corporate Credit Metrics

($ millions)

	2016E		2017E
	Post-Capital Allocation		Post-Capital Allocation
Recourse Debt *(09/30/2016)*[1]	**$8,177**		**~$7,800**
Less: 2018 and 2021 Repurchases[2]	(378)		--
2018 Maturity Reserve	-		(400)
2017 Term Loan Amortization	-		(20)
Pro Forma Corporate Debt	**~$7,800**		**~$7,400**
Mid-point 2016 Adjusted EBITDA	$3,300		$2,800
Less Adjusted EBITDA:			
GenOn[3]	(525)		(145)
NRG Yield	(885)		(865)
ROFO / Other[4]	(195)		(400)
Add:			
NRG Yield Dividends to NRG[5]	80		90
ROFO / Other Dividends to NRG[6]	30		110
Other Adjustments[7]	150		150
Total Recourse EBITDA	**$1,955**		**$1,740**
Corporate Debt/Corporate EBITDA	**3.99x**		**4.24x**

Interest & Dividend Savings – Increases Recurring FCFbG[8]

	Principal Reduction	Annual Free Cash Flow Impact
Debt reduced[9]	$1,023	$94
Impact of Term Loan Refinancing[10]	-	(16)
Convertible Preferred Stock redeemed[11]	345	10
Total		**$88**

Maintaining Balance Sheet Metrics In Line With Targets

[1] Includes NRG Energy Inc. term loan facility, senior notes and tax exempt bonds; [2] Includes $186 MM and $192 MM of debt reduction completed on October 19 and November 3, 2016, respectively; [3] Net of shared service payment by GenOn to NRG; reflects impact of monetization of hedges; [4] 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; [5] 2016 and 2017estimate based on NYLD dividends equivalent to $1.00/share and $1.15/share annualized, respectively, by Q4. Excludes proceeds from potential Drop Down transactions; [6] Distributions from NRG ROFO, MWG and other non-recourse project subsidiaries; increase in 2017 primarily from MWG following environmental compliance and Ivanpah ramp-up; [7] Reflects non-cash expenses (i.e. nuclear amortization, equity compensation, and bad debt expense) that are included in reported Adjusted EBITDA; [8] Since 3Q15 ; [9] Comprised of 2015 corporate debt reduction of $246 MM, YTD Sept 2016 of $399 MM, and $186 MM and $193 MM of 2018 and 2021 Senior Notes retired in October and November 2016 respectively; [10] Increased interest on refinanced portion of Term loan. Interest savings on repurchased portion of term loan included in debt reduced above; [11] $345 MM represents liquidation preference of $1,378 per share on 250,000 shares.

Closing Remarks

2016 Scorecard

- ☑ **Deliver on 2016 Operational and Financial Objectives**

- ☑ **Strengthen the Balance Sheet and Create Financial Flexibility to Manage Commodity Cycles**
  - ☑ Extended $6.2 Bn of debt beyond 2020
  - ☑ Reduced leverage profile by $1 Bn since 3Q15
  - ☑ Unlocked $145 MM annually by better aligning dividend policy to market
  - ☑ $1.5 Bn target allocation for corporate deleveraging / convertible preferred

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- ☑ **Simplify the Company and Streamline the Organization**
  - ☑ $650 MM+ reduction in capex beginning in 2017
  - ☑ $400 MM recurring cost savings on track
  - ☑ $563 MM asset sales completed, exceeded $500 MM target

- ☑ **Partner with NRG Yield to Reinvigorate Capital Replenishment**
  - ☑ Dedicated management team at NRG Yield
  - ☑ CVSR Drop Down (closed 3Q'16)
  - ☑ Continue partnerships with Renewables
  - ☑ SunEdison utility-scale and distributed generation asset transactions

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- ☑ **Bring GreenCo Process to Conclusion with No Change to 2016 Guidance**

- ❑ **Address GenOn Capital Structure and Near-term Maturities**

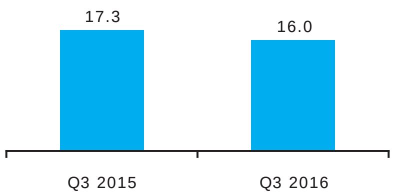
Q&A

Appendix: Operations

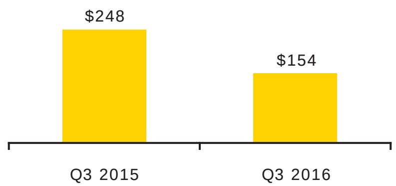
Year over Year Performance Drivers

Gulf Coast

Generation (TWh)



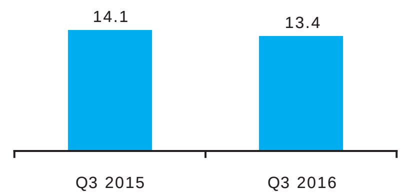
EBITDA ($ MM)



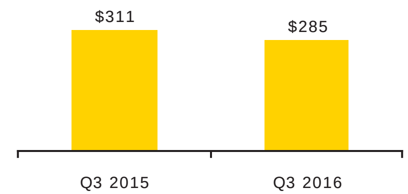
- **$94 MM lower Adjusted EBITDA due to:**
  - Lower realized energy margins in Texas from the decline in power prices
  - Lower South Central capacity revenues

East

Generation (TWh)



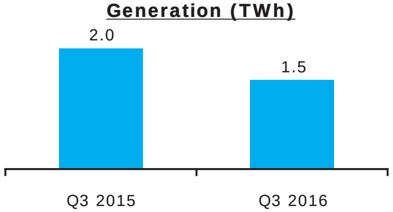
EBITDA ($ MM)



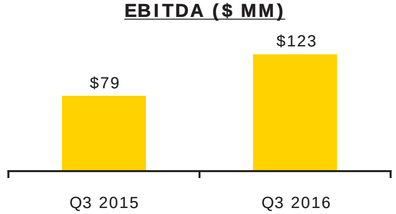
- **$26 MM lower Adjusted EBITDA due to:**
  - Declining energy margins on lower dispatch and asset sales
  - Partially offset by monetization of hedges at GenOn plants and lower operations and maintenance costs due to decreased dispatch, reduced outage spend, plant deactivations and plant sales

West

Generation (TWh)



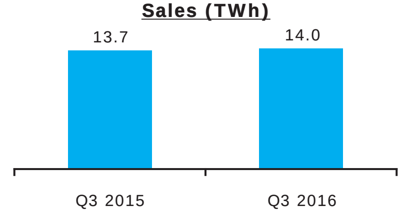
EBITDA ($ MM)



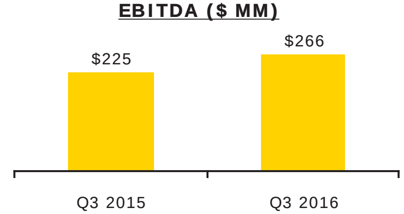
- **$44 MM higher Adjusted EBITDA**
  - Gain on sale of land at Potrero site
  - Partially offset by lower capacity margins

Retail

Sales (TWh)



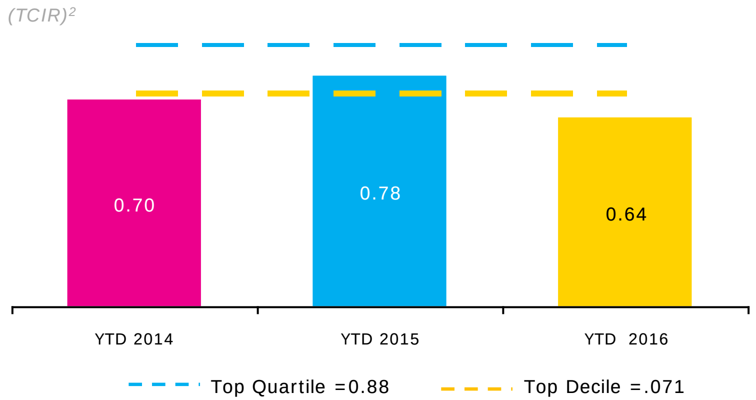
EBITDA ($ MM)



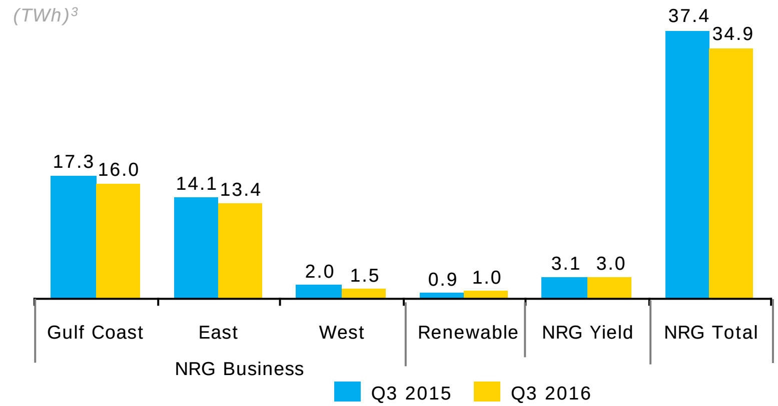
- **$41 MM higher Adjusted EBITDA due to:**
  - Lower operating expenses as a result of operating efficiencies
  - Favorable gross margin as a result of lower supply costs and increased volumes from higher customer count and favorable weather

Generation/Business: Operational Metrics

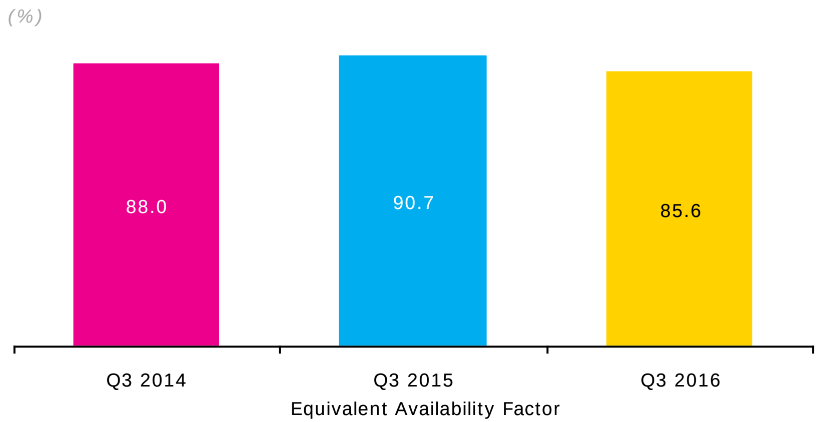
Safety[1]



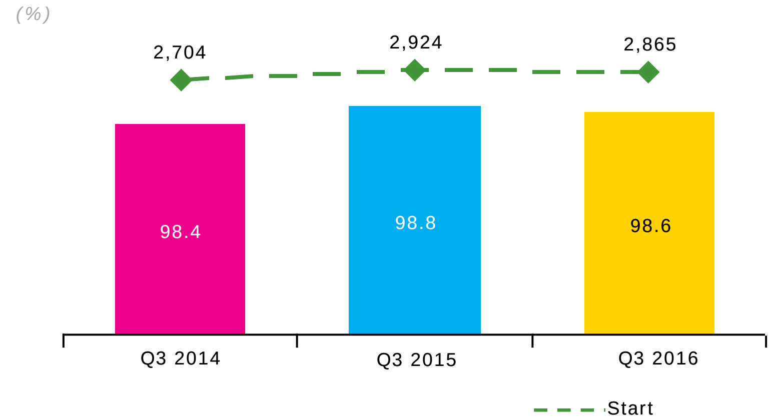
Production



Coal and Nuclear Availability



Gas and Oil Starts and Reliability



Top Decile Safety Performance

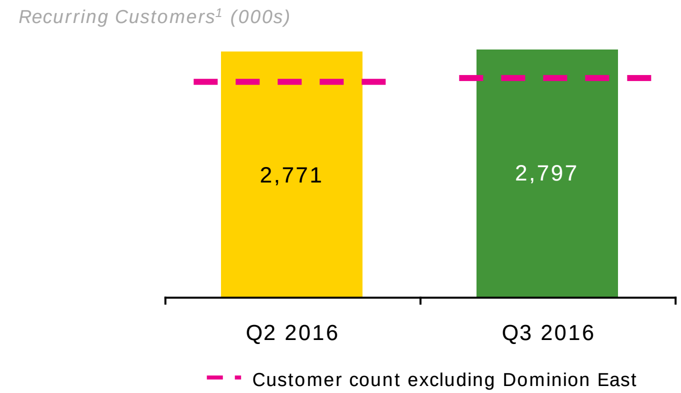
[1] Excludes Goal Zero, NRG Home Services and NRG Home Solar; Top decile and top quartile based on Edison Electric Institute 2015 Total Company Survey results; [2] TCIR = Total Case Incident Rate; [3] All NRG-owned domestic generation; Excludes line losses, station service, and other items. Generation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

Retail Mass: Operational Metrics

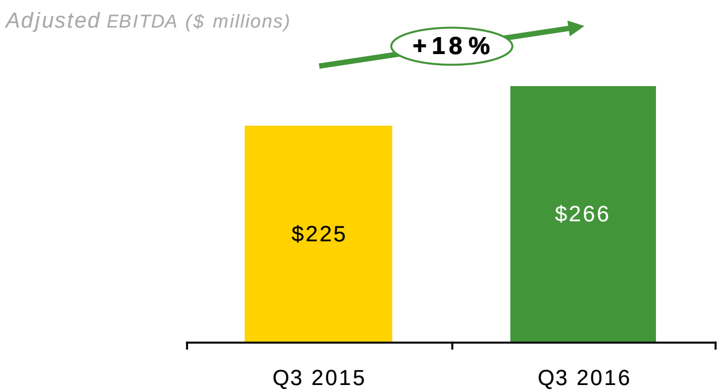
3rd Quarter Highlights

- One of the strongest quarters ever for Retail
- Delivered $266 MM Adjusted EBITDA, driven by operating efficiencies and favorable supply costs
- Grew recurring customer count

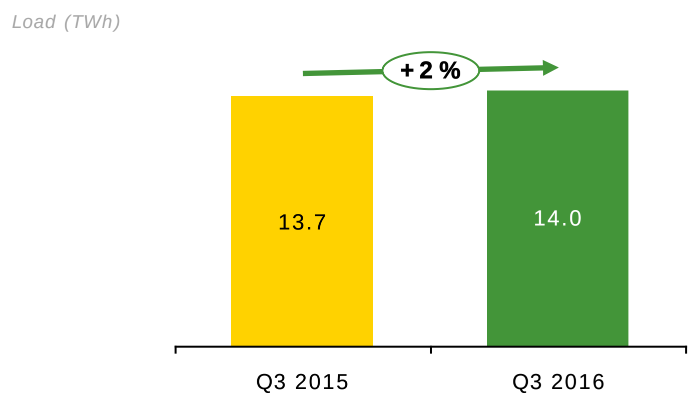
Expanded Customer Count



Surpassed 2015's Q3 Results…



…At Comparable Volumes



Retail Delivers a Benchmark Third Quarter, Enabled by Cost Efficiencies and Low Supply Costs

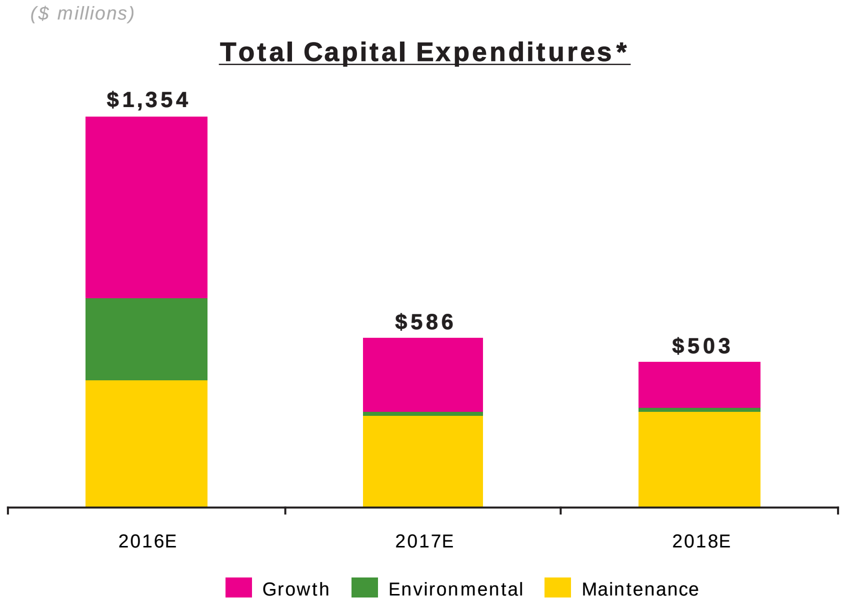
[1] Excludes C&I and NRG Home Solar customers; recurring customer count includes customers that subscribe to one or more recurring services, such as electricity and natural gas

Modernizing the Portfolio

Delivering on Major Capex Spend

		MW	Project Description	Estimated COD
Fuel Conversion / Environmental / New Capacity	Shawville 1-4[1]	597	Natural Gas	Q4 2016
	Powerton 5 & 6[2]	1,538	DSI & ESP Upgrade	Q4 2016
	Bacliff Peakers	360	New Generation	Q1 2017
	Carlsbad Peakers[3]	527	New Generation	Q4 2018
	Canal Peaker[4]	333	New Generation	Q2 2019
	Puente Peaker[4]	262	New Generation	Q2 2020
	Utah Solar Assets	265	SunEdison	Q4 2016
	Texas Solar Assets	154	SunEdison	Q4 2017 - Q2 2018
Other	UPMC[5]		CHP	Q1 2018
	Petra Nova		Carbon Capture	Q4 2016

Nearing Completion of Capex Cycle



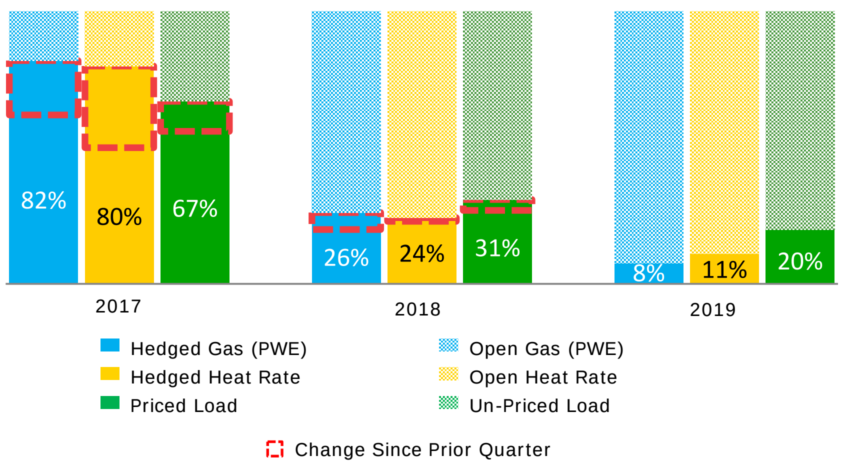
*Change in 2016 primarily $190 MM SunEdison transactions net of timing differences between 2016 and 2017

Successfully Delivering on Major Capex Program

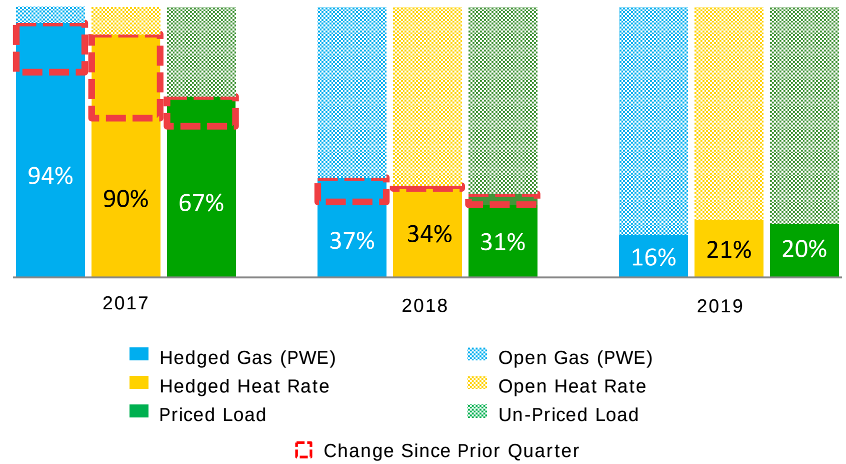
[1] GenOn Facility; [2] Assets owned by Midwest Generation; [3] Carlsbad – Pending California appeals court review; [4] Subject to applicable regulatory approvals and permits; [5] Yield acquisition

Managing Commodity Price Risk

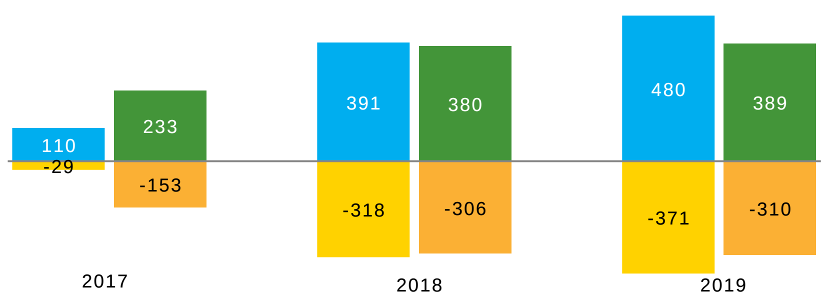
Total Portfolio Generation and Retail Hedge Position[1,2, 5]



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



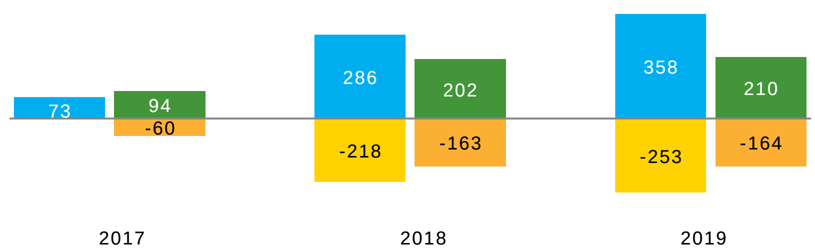
Total Portfolio Sensitivity to Gas Price and Heat Rate[1,3,5]



Henry Hub Gas as of 10/28	3.19	3.03	2.94

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 10/28	3.19	3.03	2.94

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 10/28/2016 ; [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 90% and 39% 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]		
	2017	2018	2019	2017	2018	2019	2017	2018	2019
Net Coal and Nuclear Capacity (MW)[2]	6,290	6,290	6,290	7,465	7,465	7,465	4,198	4,198	4,198
Forecasted Coal and Nuclear Capacity (MW)[3]	4,758	4,489	4,250	3,652	2,823	2,258	1,932	1,603	1,284
Total Coal and Nuclear Sales (GWh)[4]	39,102	19,150	8,654	30,291	4,809	283	16,092	1,914	0
Percentage Coal and Nuclear Capacity Sold Forward[5]	94%	49%	23%	95%	19%	1%	95%	14%	0%
Total Forward Hedged Revenues [6]	$1,430	$735	$436	$1,101	$159	$11	$605	$66	$0
Weighted Average Hedged Price ($ per MWh)[6]	$36.56	$38.37	$50.39	$36.35	$33.04	NA	$37.58	$34.67	NA
Average Equivalent Natural Gas Price ($ per MMBtu)[6]	$3.52	$3.82	$4.80	$3.14	$3.15	NA	$3.05	$3.31	NA
Gross Margin Sensitivities: Gas Price Sensitivity Up $0.50/MMBtu on Coal and Nuclear Units	$1	$84	$142	$72	$203	$217	$38	$115	$111
Gross Margin Sensitivities: Gas Price Sensitivity Down $0.50/MMBtu on Coal and Nuclear Units	$42	($73)	($110)	($39)	($144)	($144)	($9)	($78)	($75)
Gross Margin Sensitivities: Heat Rate Sensitivity Up 1 MMBtu/MWh on Coal and Nuclear Units	$41	$96	$92	$53	$106	$117	$26	$52	$56
Gross Margin Sensitivities: Heat Rate Sensitivity Down 1 MMBtu/MWh on Coal and Nuclear Units	($25)	($80)	($78)	($35)	($83)	($86)	($11)	($41)	($43)

[1] Portfolio as of 10/28/2016
[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 10/28/2016, 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 10/28/2016, and then combined with power sales to arrive at equivalent GWh hedged; The Coal and Nuclear Sales include swaps and delta of options sold which is subject to change; Actual value of options will include the impact of non-linear factors; For detailed information on the Company's hedging methodology through use of derivative instruments, see discussion in 2015 10K Item 15 - Note 5, Accounting for Derivative Instruments and Hedging Activities, to the Consolidated Financial Statements; Includes inter-segment sales from the Company's wholesale power generation business to the Retail Business
[5] Percentage hedged is based on Total Coal and Nuclear sales as described above ([4]) divided by the forecasted Coal and Nuclear Capacity ([3])
[6] Represents all coal and nuclear sales, including energy revenue and demand charges.
[7] GenOn disclosure not additive to other regions

Commodity Prices

Forward Prices[1]	2017	2018	2019	Annual Average for 2017-2019
NG Henry Hub	$3.19	$3.03	$2.94	$3.05
PRB 8800	$11.90	$12.44	$13.20	$12.51
NAPP MG2938	$48.49	$46.00	$47.00	$47.16
ERCOT Houston Onpeak	$37.88	$36.63	$36.40	$36.97
ERCOT Houston Offpeak	$24.29	$23.08	$22.43	$23.27
PJM West Onpeak	$40.48	$37.97	$36.43	$38.29
PJM West Offpeak	$27.83	$25.95	$25.41	$26.40

[1] Prices as of 10/28/2016

Fuel Statistics

	3Q		Year To Date	
Domestic[1]	**2016**	**2015**	**2016**	**2015**
Coal Consumed (mm Tons)	9.4	11.1	21.3	32.0
PRB Blend	**71%**	**72%**	**70%**	**72%**
East	57%	63%	57%	61%
Gulf Coast	81%	77%	79%	81%
Bituminous	**18%**	**12%**	**17%**	**14%**
East	43%	25%	40%	30%
Lignite & Other	**11%**	**16%**	**13%**	**14%**
East	0%	12%	3%	9%
Gulf Coast	19%	23%	21%	19%
Cost of Coal ($/Ton)	**$ 38.96**	**$ 39.40**	**$ 39.16**	**$ 40.95**
Cost of Coal ($/mmBtu)	**$ 2.15**	**$ 2.27**	**$ 2.18**	**$ 2.33**
Cost of Gas ($/mmBtu)	**$ 2.47**	**$ 2.51**	**$ 2.25**	**$ 2.92**

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

3Q 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	12,512	12,910	(398)	(3%)	90%	53%	93%	55%
Gulf Coast – South Central	3,468	4,374	(906)	(21%)	88%	38%	91%	48%
East	13,438	14,118	(680)	(5%)	87%	29%	92%	27%
West	1,464	1,964	(500)	(25%)	92%	11%	95%	14%
Renewables	978	930	48	5%	96%	35%	96%	27%
NRG Yield4	2,990	3,113	(123)	(4%)	97%	25%	98%	26%
Total	**34,850**	**37,409**	**(2,558)**	**(7%)**	**90%**	**33%**	**93%**	**33%**
Gulf Coast – Texas Nuclear	2,513	2,518	(5)	(0%)	100%	97%	100%	97%
Gulf Coast – Texas Coal	7,081	7,332	(251)	(3%)	88%	76%	96%	79%
Gulf Coast – South Central Coal	1,064	1,195	(131)	(11%)	74%	52%	83%	59%
East Coal	8,640	10,366	(1,726)	(17%)	84%	52%	88%	46%
Baseload	**19,299**	**21,412**	**(2,113)**	**(10%)**	**86%**	**64%**	**91%**	**59%**
Renewables Solar	518	435	83	19%	100%	33%	98%	29%
Renewables Wind	460	495	(35)	(7%)	95%	35%	95%	27%
NRG Yield Solar	380	363	17	5%	100%	38%	100%	36%
NRG Yield Wind	1,364	1,233	131	11%	97%	30%	96%	27%
Intermittent	**2,722**	**2,526**	**195**	**8%**	**97%**	**32%**	**96%**	**28%**
East Oil	840	592	248	42%	95%	6%	92%	4%
Gulf Coast – Texas Gas	2,917	3,059	(142)	(5%)	89%	25%	90%	26%
Gulf Coast – South Central Gas	2,404	3,179	(775)	(24%)	92%	34%	93%	45%
East Gas	3,958	3,160	798	25%	84%	25%	95%	21%
West Gas	1,464	1,964	(500)	(25%)	92%	11%	95%	14%
NRG Yield Conventional	629	957	(328)	(34%)	97%	15%	100%	22%
NRG Yield Thermal[4]	618	560	58	10%	98%	46%	92%	32%
Intermediate / Peaking	**12,830**	**13,471**	**(641)**	**(5%)**	**91%**	**19%**	**94%**	**19%**

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

YTD 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	29,310	33,631	(4,322)	(13%)	90%	42%	90%	48%
Gulf Coast – South Central	10,207	12,583	(2,376)	(19%)	86%	37%	79%	46%
East	29,060	39,760	(10,700)	(27%)	80%	20%	83%	25%
West	3,265	3,194	71	2%	86%	8%	85%	8%
Renewables	2,968	2,790	178	6%	96%	36%	96%	31%
NRG Yield4	8,570	8,368	202	2%	96%	23%	95%	23%
Total	**83,380**	**100,327**	**(16,947)**	**(17%)**	**86%**	**26%**	**86%**	**29%**
Gulf Coast – Texas Nuclear	7,468	6,985	482	7%	99%	97%	92%	91%
Gulf Coast – Texas Coal	16,180	20,181	(4,001)	(20%)	87%	59%	90%	73%
Gulf Coast – South Central Coal	2,209	4,458	(2,249)	(50%)	77%	36%	71%	58%
East Coal	19,690	31,183	(11,493)	(37%)	70%	35%	81%	45%
Baseload	**45,547**	**62,807**	**(17,260)**	**(27%)**	**78%**	**48%**	**84%**	**56%**
Renewables Solar	1,330	1,172	157	13%	100%	28%	98%	25%
Renewables Wind	1,639	1,618	21	1%	96%	38%	96%	33%
NRG Yield Solar	1,012	987	25	3%	100%	34%	100%	33%
NRG Yield Wind	4,551	3,826	725	19%	97%	34%	96%	29%
Intermittent	**8,531**	**7,603**	**928**	**12%**	**97%**	**34%**	**97%**	**30%**
East Oil	1,384	1,483	(99)	(7%)	93%	3%	87%	3%
Gulf Coast – Texas Gas	5,662	6,465	(803)	(12%)	91%	16%	90%	19%
Gulf Coast – South Central Gas	7,997	8,125	(128)	(2%)	89%	37%	82%	41%
East Gas	7,986	7,094	892	13%	81%	17%	82%	16%
West Gas	3,265	3,194	71	2%	86%	8%	85%	8%
NRG Yield Conventional	1,265	1,818	(552)	(30%)	94%	10%	93%	14%
NRG Yield Thermal[4]	1,742	1,738	4	0%	93%	29%	93%	26%
Intermediate / Peaking	**29,301**	**29,917**	**(615)**	**(2%)**	**88%**	**14%**	**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

PJM Capacity Clears: Merchant Wholesale Generation

PJM Region	Planning Year	Average Price ($/MW-day)	MWs Cleared	Average Price ($/MW-day)	MWs Cleared
		Base Product		Capacity Performance Product	
ComEd	2016-2017	$59.08	443	$134.00	3,006
	2017-2018	$120.00	753	$151.50	3,227
	2018-2019	NA	NA	$215.00	3,509
	2019-2020	$182.77	65	$202.77	3,738
MAAC	2016-2017	$118.26	1,877	NA	NA
	2017-2018	$144.90	588	$151.50	1,753
	2018-2019	$149.98	10	$164.77	2,229
	2019-2020	$80.00	10	$100.00	2,093
EMAAC	2016-2017	$119.06	497	NA	NA
	2017-2018	$119.99	287	$151.50	204
	2018-2019	$210.63	91	$225.42	424
	2019-2020	$99.77	103	$119.77	414
DPL	2016-2017	$124.75	516	NA	NA
	2017-2018	$120.00	177	$151.50	358
	2018-2019	$210.63	98	$225.42	459
	2019-2020	NA	NA	$119.77	481
PEPCO	2016-2017	$120.19	4,313	NA	NA
	2017-2018	$121.43	1,847	$151.50	2,501
	2018-2019	$149.98	58	$164.77	3,870
	2019-2020	NA	NA	$100.00	3,879
ATSI	2016-2017	$115.90	901	NA	NA
	2017-2018	$128.74	305	$151.50	647
	2018-2019	$149.98	57	$164.77	681
	2019-2020	$80.00	2	$100.00	550
RTO	2016-2017	$80.83	926	$134.00	493
	2017-2018	$122.31	1,246	$151.50	449
	2018-2019	$149.98	249	$164.77	1,020
	2019-2020	$80.00	191	NA	NA
Net Total	**2016-2017**	**$112.89**	**9,473**	**$134.00**	**3,499**
	2017-2018	**$124.38**	**5,200**	**$151.50**	**9,140**
	2018-2019	**$170.35**	**563**	**$183.62**	**12,191**
	2019-2020	**$103.42**	**370**	**$136.02**	**11,155**

PJM Capacity Revenue by Delivery Year

	NRG	GenOn	Total
16/17	$205	$356	$561
17/18	$291	$450	$742
18/19	$363	$489	$852
19/20	$309	$260	$569

Assumptions:

- Data as of 6/30/16
- Includes imports
- Excludes NRG Demand Response and Energy Efficiency
- Excludes Aurora and Rockford
- Excludes NRG Yield Assets

SunEdison Asset Details

Transaction Overview:

- **Utility-Scale:** $129 MM initial consideration plus $59 MM in earn-out potential
- **Distributed Generation (DG):** $68 MM total consideration

($ millions)

	Asset	Status	PPA Tenure	Gross MW_{DC}	Owned MW_{AC}	Upfront Price	Earn-Out	Post Financing Effective Price	Project Non-Recourse Debt	Expected COD
Utility-Scale Assets 2.1 GW_{DC} / 1.5 GW_{AC} [1] – Utah	Four Brothers	In Operation	20 yrs	420	160[1]	$111	$0	$40-60	$315	3Q16
Utility-Scale Assets – Utah	Three Cedars	In Operation	20 yrs	263	105[1]					
	Utah: expect mid-teens levered CAFD yields[2]									
Utility-Scale Assets	**Texas Solar**	Contracted[3]	25 yrs	200	154	$16	NA	TBD	TBD	4Q17 – 2Q18
Utility-Scale Assets	**Hawaii Solar**	Advanced Development	TBD	150	111	$2	15	TBD	TBD	mid-2018
Utility-Scale Assets	**Other Solar / Wind**	Varying Stages of Development	TBD	1,105	1,008	$0.4	44	TBD	TBD	TBD
DG Assets	**East & California**	Mechanically Complete	20-25 yrs	20	17	$55	0	$9	$50-55	1Q17
DG Assets	**East NTP**	Contracted, NTP-Ready	20 yrs	16	12	$13	0			2Q17
	DG: expect high-teens levered CAFD yields[2]									

Quick Capital Replenishment:

- Strong CAFD Yields[2] with opportunity for rapid capital replenishment through project-level debt optimization and strategic partnership with NYLD
- Over 85% of purchase price justified with value from operational assets

Low-Cost Pipeline Option:

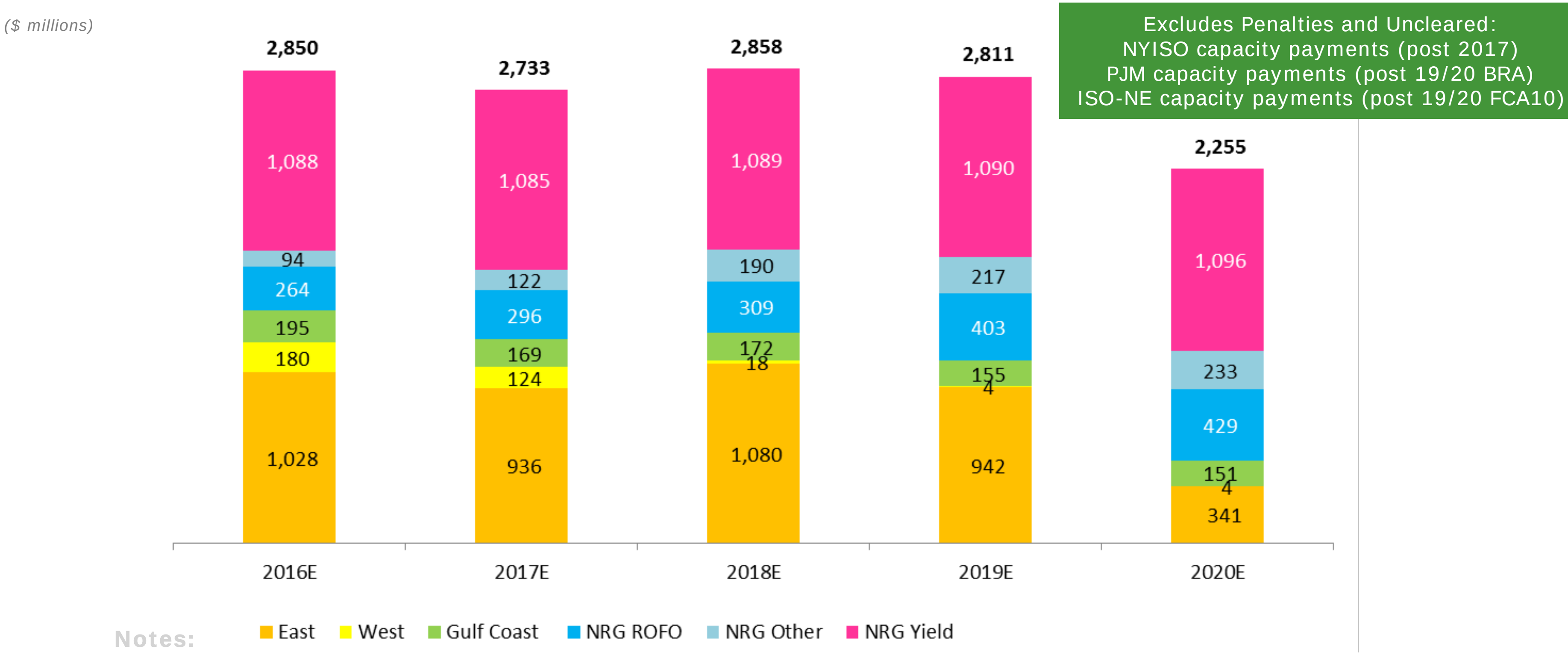
- Earn-out transaction structure mitigates backlog and pipeline conversion risk
- $16 MM Texas upfront price paid upon project close
- $15 MM in Hawaii of additional capital paid upon successful PPA negotiations
- $44 MM in pipeline paid upon reaching successful notice-to-proceed (NTP)

Acquisition Adds 300 Net MW of Near-Term Assets, 150 MW of Contracted Assets, and an Additional 1.1 GW of Development Opportunity with Attractive Risk/Return Profile

[1] Assumes 50% ownership of Utah projects reflecting NRG's net interest based on cash to be distributed in tax equity partnership with Dominion; [2] Assumes additional Tax Equity and Debt Capacity of $59 MM for the DG Assets and $51-71 MM for the Utah Assets

Appendix: Finance

Fixed Contracted and Capacity Revenue



Notes:

- East includes cleared capacity auction for PJM through May 2020, New England ISO through Forward Capacity Auction 10(FCA10) through May 2020; NY on rolling forward basis
- West includes committed Resource Adequacy contracts & tolling agreements
- Gulf Coast region includes South Central capacity sold into PJM/MISO auctions and Co-Op contracted revenues. Co-Op contracted revenues are also incorporated in the hedge table
- NRG ROFO includes all wind, solar and conventional assets which are part of ROFO agreement including projects under construction (Carlsbad and Puente)
- NRG Other includes renewable assets which are not part of ROFO and preferred resources projects
- NRG Yield includes contracted capacity, contracted energy and contracted steam revenues

YTD 3Q 2016 Capital Expenditures and Growth Investments

($ millions)	Maintenance	Environmental	Growth Investments	Total
Capital Expenditures				
Generation				
Gulf Coast	$ 130	7	5	**$ 142**
East	107	230	99	**436**
West	2	-	25	**27**
Business Solutions	6	-	1	**7**
Retail Mass	11	-	-	**11**
Renewables	12	-	159	**171**
NRG Yield	12	-	4	**16**
Corporate	25	-	63	**88**
Total Cash Capital Expenditures	**$ 305**	**$ 237**	**$ 356**	**$ 898**
Other Investments[1]	-	-	75	**75**
Project Funding, net of fees[2]	-	-	(137)	**(137)**
Total Capital Expenditures and Growth Investments, net	**$ 305**	**$ 237**	**$ 294**	**$ 836**

[1] Includes investments, restricted cash; [2] Includes net debt proceeds, cash grants, third-party contributions, and insurance proceeds

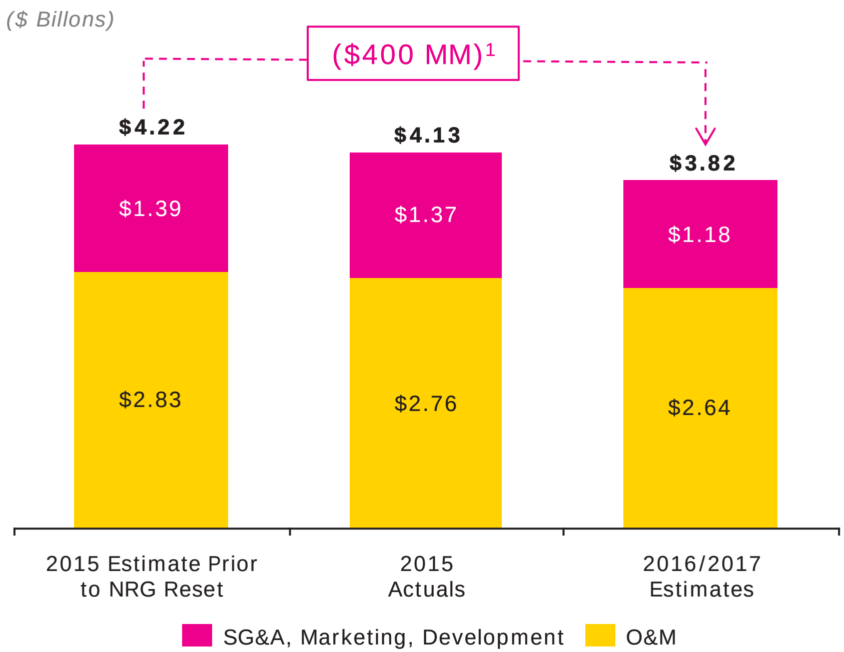
Projected Capex, Net of Financing

($ millions)		2016	2017	2018
NRG Level	Growth[1]	500	245	155
	Environmental	230	15	9
	Maintenance	275	211	215
GenOn	Growth Investments and Conversions	120	6	4
	Environmental	53	-	-
	Maintenance	134	72	93
Other[2]	Growth	7	2	-
	Environmental	-	-	-
	Maintenance	35	35	27
	Total Capex:	**$1,354**	**$586**	**$503**

[1] Excludes Canal 3; [2] Other includes NYLD, Ivanpah, and Agua Caliente

Tracking Streamlining Initiatives

On Track to Achieve Targeted $400 MM



$ Billions	2015A
Operations and Maintenance	$2.31
Other Cost of Operations	.47
Total Operations & Maintenance	2.78
LESS: Plant sales	(0.02)
Adjusted Operations & Maintenance	**$2.76**
Selling, general and administrative expense	$1.22
Development costs	0.15
Total SG&A and Development	**$1.37**
Source: NRG 2015 10K, page 66	

- ☑ **On Track:** $150 MM recurring SG&A and Development Savings[2]
- ☑ **On Track:** $100 MM recurring O&M Savings[3]
- ☑ **On Track:** $150 MM of recurring fornrg EBITDA-accretive savings executed over 2016-2017

[1] Includes fixed and variable O&M, excludes plant sales; [2] As identified on the Sept 2015 NRG Reset Call; formerly referred to as 'overhead savings'; [3] $100 MM O&M savings per 3Q15 call

Generation Organizational Structure

NRG Energy, Inc. (46,390[1] MW)

Renewables (1,130 MW)

Solar

- Agua Caliente
- Community Solar
- Distributed Solar
- Georgia Solar
- Guam
- Ivanpah
- Spanish Town
- Bingham Lake

Wind

- 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 (14,941 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

West (6,085 MW)

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

East (20,789 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
- Bowline
- Canal
- Martha's Vineyard

GenOn Mid-Atlantic (4,605 MW)

- Chalk Point
- Dickerson
- Morgantown

REMA (1,703 MW)

- Blossburg
- Gilbert
- Hamilton
- Hunterstown CT
- Mountain
- Orrtana
- Portland
- Sayreville
- Shawnee
- Shawville[5]
- Titus
- Tolna
- Warren

Residential Solar (114 MW)

Other (749 MW)

- Doga
- Gladstone

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

LEGEND

- Separate Credit Facility
- 75% interest sold to NRG Yield on November 3, 2015
- Equity Investments

[1] Capacity controlled by NRG as of 09/30/2016; [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; [5] Mothballed on 05/31/15 to add natural gas capabilities, expected to return in Q4 2016

Consolidated Debt Structure

($ millions)
As of 09/30/2016

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

NRG Energy, Inc.

Revolver $2.5 BN due 2018/2021[1]	$	–
Senior notes due 2018-2027		5,827
Term loan due 2023		1,895
Tax exempt bonds due 2038-2045		455
Total	**$**	**8,177**

GenOn Energy, Inc.

Unsecured notes due 2017-2020	$ 1,830
GenOn Hunterstown WG LP	52
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]	$	250

Agua Caliente

Project financing due 2037	$	864

Ivanpah

Project financing due 2016	$	38
Project financing due 2038		1,167

Other Renewables Financings

Project financings	$	517

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	$	1,195

Thermal

Senior secured notes due 2017-2025	$	98

Renewable

Project financings[6]	$	2,957

Note: Debt balances exclude discounts and premiums
[1] $1,162 MM LC's issued and $1,374 MM Revolver available at NRG
[2] $207 MM of LC's were issued and $293 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 $590 MM, and the present value of lease payments (9.4% discount rate) for REMA operating lease is $338 MM
[4] The present value of lease payments (9.1% discount rate) for Midwest Generation operating lease is $86 MM; this lease is guaranteed by NRG Energy, Inc.
[5] $64 MM of LC's were issued and $431 MM of the Revolver was available at NYLD
[6] Includes CVSR Drop down from 09/01/2016

Recourse / Non-Recourse Debt

($ millions)	09/30/2016	06/30/2016	03/31/2016	12/31/2015
Recourse Debt				
Term Loan Facility	$ 1,895	$ 1,900	$ 1,961	$ 1,966
Senior Notes	5,827	5,889	5,962	6,165
Tax Exempt Bonds	455	455	455	455
Recourse Debt Subtotal	**$ 8,177**	**$ 8,244**	**$ 8,378**	**$ 8,586**
Non-Recourse Debt				
Total NRG Yield[1,2]	$ 5,733	$ 5,583	$ 5,634	$ 5,691
GenOn Senior Notes	1,830	1,830	1,830	1,830
GenOn Americas Generation Notes	695	695	695	695
GenOn Other (including Capital Leases)	54	55	58	59
Renewables[2]	2,586	2,487	2,495	2,550
Conventional	257	277	85	85
Non-Recourse Debt and Capital Lease Subtotal	**$ 11,155**	**$ 10,927**	**$ 10,797**	**$ 10,910**
Total Debt	**$ 19,332**	**$ 19,171**	**$ 19,175**	**$ 19,496**

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 09.30.16

Subject to restricted payments

GenOn Energy, Inc. (15,826 MW)

7.875% Unsecured Notes, due 2017	$691
9.500% Unsecured Notes, due 2018	$650
9.875% Unsecured Notes, due 2020	$489
Secured Revolver from NRG Energy, Inc. (Intercompany)[1]	-
Total Debt[2]	**$1,830**
Consolidated Cash Balance	**$1,218**

GenOn Energy Holdings

REMA (1,703 MW)

Capital Leases	$2
Operating Leases[4]	$338
Consolidated Cash Balance	**$110**

Asset	MW	ISO
Blossburg	19	PJM
Conemaugh[3]	282	PJM
Gilbert	438	PJM
Hamilton	20	PJM
Hunterstown CT	60	PJM
Keystone[3]	285	PJM
Mountain	40	PJM
Orrtanna	20	PJM
Portland	169	PJM
Sayreville	217	PJM
Shawnee	20	PJM
Shawville [7]	6	PJM
Titus	31	PJM
Tolna	39	PJM
Warren	57	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")	**$472**

GenOn Mid-Atlantic (4,605 MW) ("MIRMA")

Operating Leases[4]	$590
Consolidated Cash Balance	**$483**

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	1,029	CAISO

Rest of GenOn Inc (6,216 MW)

Vendor Financing (Hunterstown)[6]	$52

Asset	MW	ISO
Avon Lake	659	PJM
Brunot Island	259	PJM
Cheswick	565	PJM
Choctaw [8]	800	SERC
Ellwood	54	CAISO
Etiwanda	640	CAISO
Hunterstown CCGT	810	PJM
Mandalay	560	CAISO
New Castle	328	PJM
Niles	25	PJM
Ormond Beach	1,516	CAISO

[1]$207MM of LC's were issued and $293MM of the Intercompany Revolver was available; [2]Excludes premium of $92MM 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 $52MM; [6] GAAP classification for portion of LTSA payments; [7]Mothballed in May 2015, Shawville units 1, 2,3 & 4 (597MW) expected to return to service no later than Q42016; 8 Includes 275 MW related to Choctaw Unit 1 which is in forced outage

Schedule of Debt Maturities

$ in millions as of September 30, 2016			Nonrecourse to NRG	
Issuance	**Maturity Year**	**NRG Recourse**	**GenOn**	**Yield**
7.875% GenOn Senior Notes	**2017**	$ -	$ 691	$ -
7.625% NRG Senior Notes	2018	584	-	-
9.50% GenOn Senior Notes	2018	-	650	-
	2018 Total	**584**	**650**	**-**
3.5% NRG Yield, Inc. Convertible Notes	**2019**	**-**	**-**	**345**
9.875% GenOn Senior Notes	2020	-	489	-
3.25% NRG Yield, Inc. Convertible Notes	2020	-	-	288
	2020 Total	**-**	**489**	**288**
7.875% NRG Senior Notes	2021	399	-	-
8.50% GenOn Americas Generation Senior Notes	2021	-	366	-
	2021 Total	**399**	**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	1,895		
6.625% NRG Senior Notes	2023	869	-	-
	2023 Total	**2,764**	**-**	**-**
6.25% NRG Senior Notes	2024	733	-	-
5.375% Yield Operating LLC Senior Notes	2024	-		500
	2024 Total	**733**	**-**	**500**
7.25% NRG Senior Notes	**2026**	**1,000**	**-**	**-**
6.625% NRG Senior Notes	**2027**	**1,250**	**-**	
5% NRG Yield Operating LLC Senior Notes	**2027**	**-**	**-**	**350**
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**	**-**	**-**
Yield Operating LLC Revolver	**Various**	**-**	**-**	**-**
	Subtotal	**8,177**	**2,525**	**1,483**
Non-Recourse Project Debt and Capital Leases[1]	**Various**		**54**	**4,250**
	Total Debt		**$ 2,579**	**$ 5,733**

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: QTD and YTD 3Q 2016 Free Cash Flow before Growth

($ millions)	3 months ended 9/30/2016	9 months ended 9/30/2016
Adjusted EBITDAR	$ 1,206	$ 2,865
Less: GenOn & EME operating lease expense	(33)	(100)
Adjusted EBITDA	$ 1,173	$ 2,765
Interest payments	(226)	(802)
Debt Extinguishment Cash Costs	(44)	(99)
Income tax	---	(10)
Collateral / working capital / other	(44)	(122)
Cash Flow from Operations	$ 860	$ 1,733
Reclassifying of net receipts (payments) for settlement of acquired derivatives that include financing elements	26	129
Merger, integration and cost-to-achieve expenses[1]	22	47
Sale of Potrero land	74	74
Return of capital from equity investments[2]	(5)	6
Collateral	119	(231)
Adjusted Cash Flow from Operations	$ 1,096	$ 1,758
Maintenance capital expenditures, net [3]	(103)	(272)
Environmental capital expenditures, net	(48)	(237)
Preferred dividends	--	(2)
Distributions to non-controlling interests [4]	(34)	(116)
Consolidated Free Cash Flow before Growth	$ 911	$ 1,131
Less: FCFbG at Non-Guarantor Subsidiaries[5]	(509)	(607)
NRG-Level Free Cash Flow before Growth	$ 402	$ 524

[1] Cost-to-achieve expenses associated with the $150MM savings announced on September 2015 call [2] Represents cash distributions to NRG from equity investments
[3] Includes insurance proceeds of $33MM [4] Excludes $87M 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: 2016 and 2017 Guidance

Appendix Table A-1: 2016 and 2017 Guidance

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

($ millions)	2016 Prior Guidance	2016 Revised Guidance	2017 Guidance
Generation and Renewables	$1,545 - $1,670	$1,640 - $1,690	$1,135 - $1,255
Retail Mass	650 – 725	725 – 775	700 – 780
NRG Yield	805	885	865
Adjusted EBITDA	**$3,000 - $3,200**	**$3,250 - $3,350**	**$2,700 - $2,900**
Interest payments	(1,090)	(1,115)	(1,065)
Debt Extinguishment Cash Cost	(100)	(120)	--
Income tax	(40)	(40)	(40)
Working capital / other	75	25[1]	(240)[1]
Adjusted Cash Flow from Operations	**$1,845 - $2,045**	**$2,000 - $2,100**	**$1,355 - $1,555**
Maintenance capital expenditures, net	(435) - (465)	(435) - (450)	(310) - (340)
Environmental capital expenditures, net	(285) - (315)	(280) - (290)	(10) - (30)
Preferred dividends	(2)	(2)	--
Distributions to non-controlling interests[2]	(170) – (180)	(160) – (170)	(185) – (205)
Consolidated Free Cash Flow before Growth	**$1,000 - $1,200**	**$1,100 - $1,200**	**$800 - $1,000**
Less: FCFbG at Non-Guarantor Subsidiaries[3]	(250)	(420)	(100)
NRG-Level Free Cash Flow before Growth	**$750 - $950**	**$680 - $780**	**$700 - $900**

[1] Change primarily driven by 2016 inflows from a reduction in fuel inventory of $130MM, increases in asset retirement, deactivation and other liability payments of ($70MM), cash adjustment to equity earnings increase of ($15MM), eVgo California settlement payments increase of ($10MM), and pension cash contribution increase of ($10MM); [2] Includes Yield distributions to public shareholders, and Capistrano and Solar distributions to non-controlling interests; [3] Reflects impact from GenOn, NRG Yield, and other excluded project subsidiaries

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Appendix Table A-2: Third Quarter 2016 Adjusted EBITDA Reconciliation by Operating Segment
The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to net income/(loss)

($ millions)	Retail Mass	Generation	Renewables	NRG Yield	Corp/Elim	Total
Net income/(loss)	2	630	11	47	(297)	393
Plus:						
Interest expense, net	-	14	34	70	157	275
Income tax	-	(2)	(3)	13	41	49
Loss on debt extinguishment	-	-	-	-	50	50
Depreciation, amortization, and ARO expense	25	198	48	76	16	363
Amortization of contracts	(1)	(15)	-	17	-	1
EBITDA	**26**	**825**	**90**	**223**	**(33)**	**1,131**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	-	7	2	23	(2)	30
Reorganization costs	-	-	-	-	6	6
Deactivation costs	-	3	-	-	1	4
Gain on sale of business	-	(194)	-	-	(4)	(198)
Other non recurring charges	-	6	(6)	-	-	-
Impairments	-	13	(1)	-	4	16
Mark to Market (MtM) losses/(gains) on economic hedges	240	(55)	(1)	-	-	184
Adjusted EBITDA	**266**	**605**	**84**	**246**	**(28)**	**1,173**

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Appendix Table A-3: Third Quarter 2015 Adjusted EBITDA Reconciliation by Operating Segment

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

($ millions)	Retail Mass	Generation	Renewables	NRG Yield	Corp/Elim	Total
Net income/(loss)	197	164	(16)	32	(310)	67
Plus:						
Interest expense, net	-	17	22	70	177	286
Income tax	-	2	(4)	8	41	47
Loss on debt extinguishment	-	-	-	2	-	2
Depreciation, amortization, and ARO expense	30	231	46	71	17	395
Amortization of contracts	(1)	(11)	-	14	-	2
EBITDA	**226**	**403**	**48**	**197**	**(75)**	**799**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	-	10	3	20	(4)	29
Acquisition-related transaction & integration costs	-	-	-	1	2	3
Deactivation costs	-	2	-	-	-	2
Gain on sale of business	-	-	(2)	-	-	(2)
Other non recurring charges	(13)	8	6	1	-	2
Impairments	36	222	5	-	-	263
Mark to Market (MtM) (gains)/losses on economic hedges	(24)	29	-	2	-	7
Adjusted EBITDA	**225**	**674**	**60**	**221**	**(77)**	**1,103**

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Appendix Table A-4: YTD Third Quarter 2016 Adjusted EBITDA Reconciliation by Operating Segment
The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to net income/(loss)

($ millions)	Retail Mass	Generation	Renewables	NRG Yield	Corporate	Total
Net income / (loss)	644	418	(102)	111	(907)	164
Plus:						
Interest expense, net	-	56	84	212	478	830
Income tax	-	(1)	(14)	25	85	95
Loss on debt extinguishment	-	-	-	-	119	119
Depreciation, amortization, and ARO expense	80	506	144	226	50	1,006
Amortization of contracts	-	(46)	-	57	(3)	8
EBITDA	**724**	**933**	**112**	**631**	**(178)**	**2,222**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	-	23	16	58	(4)	93
Acquisition-related transaction & integration costs	-	-	-	-	7	7
Reorganization costs	5	1	3	-	17	26
Deactivation costs	-	15	-	-	1	16
(Gain)/loss on sale of business	-	(223)	-	-	79	(144)
Other non recurring charges	-	17	5	3	2	27
Impairments	-	226	25	-	19	270
Mark to Market (MtM) (gains)/losses on economic hedges	(100)	348	-	-	-	248
Adjusted EBITDA	**629**	**1,340**	**161**	**692**	**(57)**	**2,765**

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Appendix Table A-5: YTD Third Quarter 2015 Adjusted EBITDA Reconciliation by Operating Segment
The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to net income/(loss)

($ millions)	Retail Mass	Generation	Renewables	NRG Yield	Corporate	Total
Net income/(loss)	523	213	(74)	53	(793)	(78)
Plus:						
Interest expense, net	-	52	61	199	532	844
Income tax	-	3	(13)	8	(41)	(43)
Loss on debt extinguishment	-	-	-	9	-	9
Depreciation, amortization, and ARO expense	94	706	134	224	43	1,201
Amortization of contracts	-	(41)	1	40	1	1
EBITDA	**617**	**933**	**109**	**533**	**(258)**	**1,934**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	-	22	13	34	(2)	67
Acquisition-related transaction & integration costs	1	-	-	2	13	16
Deactivation costs	-	8	-	-	-	8
Gain on sale of business	-	-	(2)	-	-	(2)
Other non recurring charges	(14)	19	5	1	-	11
Impairments	36	222	5	-	-	263
Mark to Market (MtM) (gains)/losses on economic hedges	(34)	321	2	(1)	-	288
Adjusted EBITDA	**606**	**1,525**	**132**	**569**	**(247)**	**2,585**

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Appendix Table A-6: Third Quarter 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	Business Solutions	Total
Net income / (loss)	385	216	110	(81)	630
Plus:					
Interest expense, net	14	-	-	-	14
Income tax	-	(2)	-	-	(2)
Depreciation, amortization, and ARO expense	50	127	20	1	198
Amortization of contracts	(17)	1	-	1	(15)
EBITDA	**432**	**342**	**130**	**(79)**	**825**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	-	-	2	5	7
Deactivation costs	2	-	1	-	3
Gain on sale of assets	(188)	-	(6)	-	(194)
Other non recurring charges	-	6	-	-	6
Impairments	1	13	(1)	-	13
Mark to Market (MtM) losses/(gains) on economic hedges	38	(207)	(3)	117	(55)
Adjusted EBITDA	**285**	**154**	**123**	**43**	**605**

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Appendix Table A-7: Third Quarter 2015 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	Business Solutions	Total
Net (loss)/income	(12)	124	63	(11)	164
Plus:					
Interest expense, net	17	-	-	-	17
Income tax	-	-	-	2	2
Depreciation, amortization, and ARO expense	68	143	17	3	231
Amortization of contracts	(18)	1	4	2	(11)
EBITDA	**55**	**268**	**84**	**(4)**	**403**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	-	4	3	3	10
Deactivation costs	2	-	-	-	2
Other non recurring charges	1	7	-	-	8
Impairments	222	-	-	-	222
Mark to Market (MtM) losses/(gains) on economic hedges	31	(31)	(8)	37	29
Adjusted EBITDA	**311**	**248**	**79**	**36**	**674**

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Appendix Table A-8: YTD Third Quarter 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	Business Solutions	Total
Net income / (loss)	493	(246)	73	98	418
Plus:					
Interest expense, net	56	1	-	(1)	56
Income tax	-	(2)	-	1	(1)
Depreciation, amortization, and ARO expense	162	281	55	8	506
Amortization of contracts	(52)	4	(3)	5	(46)
EBITDA	**659**	**38**	**125**	**111**	**933**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	-	5	7	11	23
Reorganization costs	-	-	-	1	1
Deactivation costs	15	-	-	-	15
Gain on sale of assets	(217)	-	(6)	-	(223)
Other non recurring charges	3	14	-	-	17
Impairments	17	151	58	-	226
Mark to Market (MtM) losses/(gains) on economic hedges	175	208	15	(50)	348
Adjusted EBITDA	**652**	**416**	**199**	**73**	**1,340**

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Appendix Table A-9: YTD Third Quarter 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	Business Solutions	Total
Net income / (loss)	181	49	30	(47)	213
Plus:					
Interest expense, net	52	-	-	-	52
Income tax	-	-	-	3	3
Depreciation, amortization, and ARO expense	220	431	46	9	706
Amortization of contracts	(50)	3	1	5	(41)
EBITDA	**403**	**483**	**77**	**(30)**	**933**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	-	5	6	11	22
Deactivation costs	5	-	3	-	8
Other non recurring charges	2	17	-	-	19
Impairments	222	-	-	-	222
Mark to Market (MtM) losses/(gains) on economic hedges	253	(20)	5	83	321
Adjusted EBITDA	**885**	**485**	**91**	**64**	**1,525**

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Appendix Table A-10: Expected 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 (loss)/income	**155**	**(179)**	**140**
Plus:			
Income tax	22	(7)	25
Interest expense, net	173	103	285
Depreciation, Amortization, Contract Amortization, and ARO Expense	124	210	360
EBITDA	**475**	**127**	**810**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	-	(6)	72
Deactivation costs	2	-	-
Gain on sale of business	(223)	-	-
Other Non-Recurring Charges	2	1	-
Reorganization Costs	1	17	-
Asset Write-Offs	-	1	3
Impairments	58	12	-
Mark to market (MtM) losses on economic hedges	210	42	-
Plus: Operating lease expense	112	21	-
Adjusted EBITDAR	**637**	**216**	**885**
Less: Operating lease expense	(112)	(21)	-
Adjusted EBITDA	**525**	**195**	**885**

[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	186	68	310
Interest expense, net	-	-	20
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 2016 and 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)	2016 FY			2017 FY		
	Genon	NYLD / Other	Total	Genon	NYLD / Other	Total
Adjusted EBITDA	**525**	**1,080**	**1,605**	**145**	**1,265**	**1,410**
Interest payments	(240)	(350)	(590)	(240)	(350)	(590)
Collateral / working capital / other	(63)	(36)	(99)	(126)	(164)	(290)
Cash Flow from Operations	**222**	**694**	**916**	**(221)**	**751**	**530**
Maintenance capital expenditures, net	(134)	(35)	(169)	(72)	(35)	(107)
Environmental capital expenditures, net	(53)	-	(53)	(7)	-	(7)
Distributions to NRG	-	(113)	(113)	-	(142)	(142)
Distributions to non-controlling interests	-	(161)	(161)	-	(174)	(174)
Free Cash Flow before Growth	**35**	**385**	**420**	**(300)**	**400**	**100**

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

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Appendix Table A-13: 2016 and 2017 Adjusted EBITDA Guidance Reconciliation: The following table summarizes the calculation of Adjusted EBITDA providing reconciliation to net income:

	2016 Adjusted EBITDA Prior Guidance		2016 Adjusted EBITDA Revised Guidance		2017 Adjusted EBITDA Guidance	
($ millions)	Low	High	Low	High	Low	High
GAAP Net Income [1]	180	380	235	335	60	260
Income tax	100	100	100	100	80	80
Interest Expense and Debt Extinguishment Costs	1,185	1,185	1,228	1,228	1,155	1,155
Depreciation, Amortization, Contract Amortization and ARO Expense	1,445	1,445	1,352	1,352	1,235	1,235
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	45	45	115	115	110	110
Other Costs [2]	45	45	220	220	60	60
Adjusted EBITDA	**3,000**	**3,200**	**3,250**	**3,350**	**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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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.