

# US Electric Utilities & IPPs

## 1Q16 Playbook: Keeping the Bear at Bay

### Equities

Americas

Electric Utilities

#### Julien Dumoulin-Smith

Analyst

julien.dumoulin-smith@ubs.com

+1-212-713 9848

#### Michael Weinstein

Associate Analyst

michael.weinstein@ubs.com

+1-212-713 3182

#### Paul Zimbardo

Associate Analyst

paul.zimbardo@ubs.com

+1-212-713 1033

#### Jeremiah Booream

Associate Analyst

jeremiah.booream@ubs.com

+1-212-713 4105

### Looking through the very mild winter to active summer to support utilities

Despite a meaningfully mild winter season, we see many of the equities as actually poised to deliver quite reasonable updates with 1Q results in coming weeks. In fact, despite the poor start to the year, we expect company updates to drive the sector ever higher. Thematically, we see legislation and regulatory reforms as the key drivers of future capex and regulatory recovery mechanisms. As a consequence, we believe any pressure on 2016 EPS estimates could be offset by de-risk and positive revisions in 2017 and 2018 earnings. While 'normalized' load growth stats could remain under pressure, we see negative results primarily accruing to uncoupled gas utilities and gas retailer providers. Specifically electric retail segments should be an offset to merchant operations given lower cost to serve – we believe NRG Energy should be the best example of this phenomenon.

### Key wins in the quarter? Focus on legislation and regulatory opportunities

We see the following as generally well positioned on updates in & around 1Q: CMS, AEE, NEE, PPL, WEC, EIX, ES, DUK, ED, WR, TLN, DYN, SCG, & SRE. Meanwhile, those facing potential headwinds include: AEP, D, PCG, ITC, & EXC. We highlight POR as facing negative updates around Carty timing, but this could set the bottom this year.

### Deleveraging moves to IPP Restructuring as companies redouble efforts

Despite significant targets for debt paydown for FY16, we think investors should not expect material execution YTD, seeing cash inflows as biased towards 2H. Rather, the focus will be on using cash to delever at below par. Specifically, we see parallels across NRG's GenOn subsidiary, DYN's IPH subsidiary, and Talen's corporate capital structure; all are poised to potentially see tenders and exchanges to retire debt at meaningful discounts. Further, managements across all three appear keen to delineate and execute on strategies within the year. While we appreciate the reasons behind TLN's run-up of late, with shares now trading at 7x EV / FMV EBITDA, in our view synergies would need to accrue beyond simply a restructuring of the debt.

### IPPs are on a roll; can it continue? We're a bit more cautious

Just when expectations had bottomed, IPP equities have rallied and significantly outperformed utilities YTD. We perceive growing caution across both the commodity and equity investment universe (see note ['Can Power Keep up with Gas?'](#)); we continue to see a divergence between negative near-term gas and coal trends against the backdrop of an improved 2017 gas forward.

### Can't miss earnings? Listen to WR, TLN, CMS, NEE, EXC, SRE, FE

What can't you miss this earnings season? Stay tuned for WR and TLN on key M&A updates, with volatility to match. NEE could announce a 'triple crown' with a meaningful quarterly beat, minimal 2016 equity needs, and significant forward visibility on renewable contracting opportunities; don't expect an increase, however, to the 6-8% EPS growth target increased only as of 3Q last year. CMS & ETR could also move with any discussion of a buyout of the Palisades nuclear plant PPA. As for EXC, following the close of the POM deal in the quarter, we look for a meaningful balance sheet and pro-forma EPS outlook. Turning to Analyst Days, we continue to like SRE into late May, with updates poised to be potentially decisive in reinvigorating confidence. That said, it all depends upon at least a PD in its pending California rate cases. Lastly, we look for FE to provide an updated FES view after the latest PPA approval from the PUCO, albeit we're still on the sidelines as Street expectations have moved up despite what is still a long road ahead back to any meaningful EPS growth at the core utilities.

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**Julien Dumoulin-Smith**

Analyst  
julien.dumoulin-smith@ubs.com  
+1-212-713 9848

**Michael Weinstein**

Associate Analyst  
michael.weinstein@ubs.com  
+1-212-713 3182

**Paul Zimbardo**

Associate Analyst  
paul.zimbardo@ubs.com  
+1-212-713 1033

**Jeremiah Booream**

Associate Analyst  
jeremiah.booream@ubs.com  
+1-212-713 4105

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## Summarizing our EPS/PT Changes

Figure 1: Changes to Earnings, Price Targets, and Ratings

		Price		Rating		Price target		2016E EPS		2017E EPS		2018E EPS	
Company	RIC	19-Apr-16	New	Old	New	Old	New	Old	New	Old	New	Old	
AES Corporation	AES.N	11.50	Neutral	Neutral	9.00	9.00	1.05	1.05	<b>1.25</b>	1.18	<b>1.43</b>	1.36	
Ameren	AEE.N	49.12	Neutral	Neutral	49.00	49.00	<b>2.48</b>	2.50	2.80	2.80	3.00	3.00	
American Electric Power	AEP.N	65.84	Buy	Buy	72.00	72.00	3.80	3.80	4.02	4.02	4.24	4.24	
Avista	AVA.N	40.72	Sell	Sell	36.00	36.00	2.06	2.06	2.13	2.13	2.22	2.22	
Calpine	CPN.N	15.73	Buy	Buy	17.00	17.00	<b>0.60</b>	0.54	<b>1.43</b>	1.32	<b>1.63</b>	1.61	
CMS Energy	CMS.N	41.79	Neutral	Neutral	41.00	41.00	2.02	2.02	2.16	2.16	2.31	2.31	
Consolidated Edison	ED.N	76.01	Sell	Sell	<b>66.00</b>	62.00	4.00	4.00	4.07	4.07	4.19	4.19	
Dominion	D.N	72.82	Neutral	Neutral	<b>74.00</b>	71.00	<b>3.79</b>	3.80	<b>3.88</b>	3.90	4.47	4.47	
DTE Energy	DTE.N	89.55	Buy	Buy	<b>107.00</b>	100.00	4.93	4.93	5.35	5.35	5.83	5.83	
Duke Energy	DUK.N	79.79	Buy	Buy	82.00	82.00	<b>4.59</b>	4.58	4.76	4.76	<b>4.99</b>	4.97	
Dynegy	DYN.N	17.05	Buy	Buy	21.00	21.00	<b>1.08</b>	0.91	<b>0.47</b>	0.66	<b>2.19</b>	2.31	
Edison International	EIX.N	71.42	Buy	Buy	73.00	73.00	3.86	3.86	4.13	4.13	4.31	4.31	
Empire District	EDE.N	33.45	Neutral (CBE)	Neutral (CBE)	34.00	34.00	<b>1.33</b>	1.45	<b>1.42</b>	1.52	<b>1.56</b>	1.58	
Entergy	ETR.N	76.43	Sell	Sell	<b>72.00</b>	66.00	5.12	5.12	<b>4.84</b>	4.96	<b>4.92</b>	4.97	
Eversource Energy	ES.N	57.04	Neutral	Neutral	<b>61.00</b>	59.00	2.99	2.99	3.17	3.17	3.40	3.40	
Exelon	EXC.N	34.80	Neutral	Neutral	30.00	30.00	<b>2.57</b>	2.56	<b>2.59</b>	2.61	<b>2.77</b>	2.84	
FirstEnergy	FE.N	35.50	Neutral	Neutral	<b>35.00</b>	32.00	<b>2.85</b>	2.87	<b>2.68</b>	2.83	<b>2.79</b>	2.87	
ITC Holdings	ITC.N	43.72	Neutral (CBE)	Neutral (CBE)	<b>46.00</b>	39.00	<b>2.05</b>	2.07	<b>2.30</b>	2.33	<b>2.52</b>	2.55	
NextEra Energy	NEE.N	118.10	Buy (UR)	Buy (UR)	115.00	115.00	6.18	6.18	6.50	6.50	6.92	6.92	
NRG Energy	NRG.N	14.31	Buy	Buy	<b>16.00</b>	14.00	1.18	1.18	<b>0.99</b>	0.88	<b>2.06</b>	1.90	
PG&E Corp.	PCG.N	59.58	Neutral	Neutral	62.00	62.00	3.74	3.74	3.64	3.64	3.79	3.79	
Pinnacle West Captl	PNW.N	74.85	Neutral	Neutral	<b>75.00</b>	73.00	4.05	4.05	4.19	4.19	4.54	4.54	
Portland General	POR.N	39.64	Buy	Buy	43.00	43.00	2.28	2.28	2.43	2.43	2.50	2.50	
PPL Corp.	PPL.N	37.80	Buy	Buy	38.00	38.00	2.34	2.34	<b>2.41</b>	2.43	<b>2.51</b>	2.52	
Public Service Entrp	PEG.N	47.12	Buy	Buy	49.00	49.00	<b>2.89</b>	2.90	<b>2.93</b>	2.94	2.99	2.99	
SCANA Corp.	SCG.N	69.88	Neutral	Neutral	<b>68.00</b>	66.00	4.02	4.02	4.19	4.19	4.38	4.38	
Sempra Energy	SRE.N	104.21	Buy	Buy	116.00	116.00	5.00	5.00	5.20	5.20	6.25	6.25	
Southern Company	SO.N	51.00	Sell	Sell	<b>47.00</b>	44.00	<b>2.83</b>	2.82	2.85	2.85	2.97	2.97	
Talen Energy	TLN.N	12.30	Neutral	Neutral	6.00	6.00	<b>0.67</b>	0.51	<b>(0.93)</b>	(0.95)	<b>(0.63)</b>	(0.80)	
TECO Energy	TE.N	27.78	Neutral	Neutral	27.55	27.55	1.17	1.17	<b>1.31</b>	1.30	<b>1.38</b>	1.39	
WEC Energy Group	WEC.N	59.14	Sell	Sell	53.00	53.00	<b>2.92</b>	2.93	3.09	3.09	3.30	3.30	
Westar Energy	WR.N	51.21	Neutral	Neutral	47.00	47.00	2.38	2.38	2.52	2.52	2.62	2.62	
Xcel Energy Inc.	XEL.N	41.16	Sell	Sell	<b>39.00</b>	36.00	2.20	2.20	2.30	2.30	2.40	2.40	

Source: Company Filings and UBS Estimates

**Figure 2: Visualizing Potential 1Q Beat and Misses**

BENCHMARKS	Ticker	1Q16 Earnings Center		
S&P500	SPY	0.8%	1Q16 Performance	
Utilities Select SPDR	XLU	14.6%	1Q16 Performance	
COMPETITIVE INTEGRATED	Ticker	UBSe	Consensus	Expected Beat/(Miss)
American Electric Power, Inc.	AEP	\$0.98	\$1.15	-13%
Avangrid	AGR	N/A	\$0.79	N/A
Dominion Resources	D	\$0.97	\$0.96	1%
Entergy Corp.	ETR	\$1.14	\$1.26	-9%
Exelon Corp.	EXC	\$0.64	\$0.69	-8%
FirstEnergy Corp.	FE	\$0.75	\$0.72	4%
NextEra Energy	NEE	\$1.56	\$1.35	16%
PPL Corporation	PPL	\$0.74	\$0.74	0%
Public Service Enterprise Group	PEG	\$0.87	\$0.91	-4%
Sempra Energy	SRE	\$1.63	\$1.67	-2%
Average				-1.9%
REGULATED INTEGRATED UTILITIES	Ticker	UBSe	Consensus	Expected Beat/(Miss)
Ameren Corp.	AEE	\$0.34	\$0.44	-17%
Alliant Energy Corp.	LNT	N/A	\$0.92	N/A
Avista Corp	AVA	\$0.82	\$0.82	-1%
CMS Energy	CMS	\$0.61	\$0.83	-26%
DTE Energy Co.	DTE	\$1.44	\$1.53	-5%
Duke Energy	DUK	\$1.07	\$1.17	-9%
Edison International	EIX	\$0.88	\$0.88	1%
Empire District Electric Company	EDE	\$0.26	\$0.35	-26%
Great Plains Energy	GXP	N/A	\$0.16	N/A
Hawaiian Electric Industries	HE	N/A	\$0.36	N/A
PG&E Corporation	PCG	\$0.76	\$0.74	5%
Pinnacle West Capital Co.	PNW	\$0.12	\$0.15	-19%
PNM Resources Inc.	PNM	N/A	\$0.17	N/A
Portland General Electric	POR	\$0.60	\$0.65	-10%
SCANA Corp.	SCG	\$1.41	\$1.43	-2%
Southern Company	SO	\$0.53	\$0.53	0%
TECO Energy Inc.	TE	\$0.28	\$0.26	8%
Westar Energy, Inc.	WR	\$0.47	\$0.48	-3%
WEC Energy	WEC	\$1.00	\$1.04	-5%
Xcel Energy Inc.	XEL	\$0.46	\$0.50	-7%
Average				-7.2%
REGULATED T&D UTILITIES	Ticker	UBSe	Consensus	Expected Beat/(Miss)
Consolidated Edison	ED	\$1.14	\$1.22	-7%
ITC Holdings Corp	ITC	\$0.54	\$0.50	9%
InfraREIT Inc	HIFR	N/A	\$0.25	N/A
Eversource Energy	ES	\$0.75	\$0.90	-14%
Average				-4.1%
INDEPENDENT POWER PRODUCERS	Ticker	UBSe	Consensus	Expected Beat/(Miss)
AES Corporation	AES	\$0.23	\$0.25	-9%
Calpine Corporation	CPN	\$344	\$362	-5%
Dynegy, Inc.	DYN	\$299	\$225	33%
NRG Energy Inc.	NRG	\$804	\$661	22%
Talen Energy Corp	TLN	\$186	\$188	-1%
Average				7.9%

Source: FactSet, ThomsonReuters, Company Filings and UBS Estimates

# The PM Summary of 4Q Results

**AES Corp:** We expect continued YoY pressure, but see the wider backdrop firmly focusing on the firm's role in Brazil amidst restructuring of its utility and contemplated IPP re-leveraging. Further, issues in Bulgaria remain outstanding.

**Ameren:** Shares are flat versus the broader group in 2016, oscillating around expectations for either an acquisition as well as probabilities for Missouri energy legislation. We see a positive skew to shares despite weaker quarter.

**AEP:** Large miss on mild weather, the elimination of Retail Stability Rider (RSR) payments in June 2015, and lower power prices. Inclusion of PPA formally in expectations following recently approval should increase Street estimates.

**Avista:** In-line 1Q16 with decoupling in WA, ID, and OR leading to a positive weather comp vs last year's mild temperatures. Also see a negative -\$0.03 impact from the ERM vs last year's strong meltoff, offset by rate increases and sales growth. Discussion on Salix LNG is a potential update.

**Calpine:** We expect 1Q to focus largely on re-emphasizing a deleveraging theme with cash inflows in 2H, largely inline with expectations. Potential upsides include discussion of exports and hedging success.

**CMS Energy:** Investor expectations for Michigan legislation have declined with the passage of time in the session and now there are only ~ten weeks of full session remaining before the summer recess (mid-June). Management recently lifted the long-term EPS CAGR 100bp to 6-8% without the legislation; we attribute this confidence in part to likely buyout of existing Palisades nuclear contract and subsequent replacement with ratebase capacity; positive.

**ConEd:** Shares continue to trade a ~8% P/E premium to utility peers, near a multi-year high, and versus a consistent discount during 2013-2014 (and most of 2015). While we still see the ratecase as a key risk, the question remains whether new rates will limit CECONY's ability to continue to over-earn this year. We see a wildcard upside from transmission plans on 4/28 for NY Transcos.

**Dominion:** Expect an in-line quarter with milder weather and lower farmout activity already baked in. Lower hedge pricing for Millstone is also expected. Focus on Bluewater execution and 2018 prospects should remain close focus following STR acquisition and scrutiny on filling growth post ITC tax credits.

**DTE:** Expect a strong miss on milder weather, the absence of revenue decoupling amortization, and lower REF volumes. Debate remains around Nexus, and expect an affirmative decision to build as a positive for shares.

**Duke:** This remains a well debated story among investors, discussing whether it deserves to continue to trade at a meaningful discount to Southeast peers. Adding comfort on its EPS growth through period at a 4-6% range would be key source of confidence needed to drive shares, in addition to sense on rate case timing. While Brazilian FIX has improved, don't expect a sale announcement yet.

**Dynegy:** Shares should react positively both contemplated retirement of further Midwest coal units, removing FCF drag, as well as contemplated restructuring of its IPH non-recourse subsidiary. Positive skew.

**Edison International:** We see in-line 1Q results at \$0.88 vs consensus \$0.88, with a dime of higher ratebase earnings offset by a higher effective tax rate under Tax Act Memorandum Accounting (TAMA). Upside from cost savings and cash accruals from arbitration remain upside factors.

**Empire District:** EDE has made the necessary state filings but still faces a long regulatory approval path given the number of jurisdictions. Although a prior effort at M&A was unsuccessful in 2000, Algonquin has already made commitments to retain employees and we ultimately expect the transaction to close but the ~7 month regulatory path may not be consistently smooth.

**Entergy:** We believe few updates ahead of a looking June 9 Analyst Day; focus there will remain on magnitude of ratebase growth as new efforts are unveiled. Qtr could prove a tad behind expectations.

**Eversource Energy:** A weak quarter, with mild weather only partially offset by decoupling. Also have several 1x positive regulatory items in 1Q15 that are absent this year. We see upside from renewable RFPs and legislation potential in Mass, offset by risk of yet another ROE complaint at FERC.

**Exelon:** Following the MISO auction the pressure will be on Exelon to work with IL stakeholders to craft legislation that supports the economics of its nuclear plants. With the legislature seemingly stalled in 2016 without a budget deal given the stalemate between the state legislature and the Governor, we look towards 2017 for any resolution of the road block, with odds dimming. Qtr should prove notable, albeit mixed, following close of POM acquisition.

**FirstEnergy:** FE is largely flat following the PUCO approval of the PPAs as investors increasingly see a possibility that the FERC issues an adverse order. No material updates are expected on the 1Q call. Mgmt does not intend to provide '16 guidance despite the approval of the PPA – we view this as a cautious datapoint. We include the full value of the PPA in our Price Target which appears consistent with how investors are valuing the company (~\$3/sh premium over an in-line P/E multiple). We perceive disproportionate investor focus on FE of late.

**ITC:** Fortis is waiting until it secures the minority interest stake in ITC before making the key FERC and state regulatory applications so no material updates are expected until that point in time. We read the FERC decision compelling ITC Midwest to simulate the impact of bonus depreciation and refund customers as a significant negative. We also see clear potential of a further MISO ROE complaint and limited FERC 1000 as also cautionary datapoints. No further progress appears to have been made on Lake Erie since the last call based on public data and management indicated that they might not be in a position to provide more definitive details until 2Q or later in 2016.

**NextEra Energy:** Investor focus has been on the Oncor process in Texas lately but the most significant datapoint on the upcoming call will relate to the wind/solar unregulated capex and how much equity is required in 2016. We expect minimal equity with NEE instead relying on secured project debt to 'bridge the gap'. HE is another upcoming topic of interest and we believe the market may be underestimating the possibility of the transaction getting done.

**NRG Energy:** We look for a strategy on addressing GenOn restructuring – and potential for secured debt capacity.

**PG&E Corp:** We expect a modest beat for the quarter with another -\$0.10 impact from the delayed GT&S ratecase decision partially offset by higher ratebase earnings. Can PG&E win on its rate cases remains the key question.

**Pinnacle West:** Immaterial miss of a few pennies in the lightest quarter of the year. Focus is on the ACC election primaries, which remains wide open, as well as latest prospects for a pro-solar ballot effort. Further, July decision on Tucson case should set direction for forthcoming APS rate case; we think this is likely positive.

**Portland General Electric:** Expect a miss for 1Q16 largely as a result of a rate decrease in January and a higher effective tax rate. Key question remains timing on in-service of Carty CCGT and corresponding rate treatment; we think potentially a headwind, but likely sets a low in shares for the year.

**PPL:** Shares continue to underperform in 2016 given the weakness of the GBP foreign exchange rate (~4%) and significant uncertainty around the 'Brexit' vote. Despite these macro headwinds we still see PPL as one of the cleaner large cap regulated utilities with minimal headline exposure. The latest FIX and RPI trends for the U.K. are discouraging but this is countered by PPL having among the least exposure to a reduction in ratebase from the extension of bonus depreciation with ~50% of future capex targeting the U.K. It's a Macro Call.

**PSEG:** We expect a weak 1Q for a variety of reasons, but the backdrop remains on execution towards a regulated growth profile. Quiet otherwise.

**SCANA:** See an in-line quarter with most of the discussion focused on the upcoming fixed-price option decision and the recently filed gas ratecase in North Carolina. Sales growth trends could well continue recent healthy trajectory.

**Sempra:** A miss for the quarter with several negative year-over-year comps, but real focus is on timing of a PD and decision from CPUC on its two pending rate cases, which could further delay Analyst Day timing. We reaffirm confidence the 5-year 11% EPS growth rate as its rolled forward under various scenarios.

**Southern Company:** Southern has underperformed YTD with a sharp decline following the 4Q15 update with guidance revisions that missed expectations but shares have largely tracked the market since that point. The latest Kemper update shows that there is still a fair amount of work to be done with risk around the in-service date. Vogtle costs increased (as expected based on the contractor settlement) but construction appears to be on track.

**Talen:** Talen has been a top performer and the stock has nearly doubled in the past three months as media reports have indicated that TLN could be a target of a LBO. We believe a transaction is possible, albeit with valuation already reflecting a healthy premium to peers, we find it hard to understand the valuation methodology employed for further appreciation.

**TECO:** Investors will be concentrating on probability of deal closing and related datapoints in New Mexico with hearings set for late May. We continue to expect that the transaction will be completed as TE successfully navigated its own approval of NMGC with largely the same NM Commission. Emera has also "effectively hedged" 85-95% of its currency exposure on the planned financing.

**WEC Energy:** We expect WEC to provide further updates on its capex 'backlog' (at least qualitatively) to bolster rate base growth as part of its 'iterative' process to further offset the impact of bonus depreciation.

**Westar Energy:** All eyes are on management to see whether they confirm media reports that the company is accepting bids as part of a broad strategic review. WR has historically traded at a discount but is now at a ~18% premium vs 7% discount approximately one year ago.

**Xcel:** Expect a small miss on mild weather and higher depreciation, partially offset by higher rates. Focus remains on execution of regulated growth plan in CO to offset bonus depreciation headwinds.

## Notable Beats and Misses for 1Q16

Among the widest beats, we note **NEE** at \$1.56 vs consensus \$1.35 on improved wind generation capacity factors and renewables growth at NextEra Energy Resources. Among the IPPs, we see both **DYN** and **NRG** coming in ahead of expectations despite a lower commodity deck as a result of adding the ECP and DUK portfolios to DYN and beneficially mild Gulf Coast weather for NRG's retail business.

Notable misses abound on the mild weather, but flag **AEP** on mild weather and the elimination of Retail Stability Rider (RSR) payments at Genco (as well as a lower commodity deck), even as the company moves forward with the sale of non-PPA assets. We also point to **SRE** with the passthrough of repairs tax benefits this year through its Tax Act Memorandum Account and **CMS** with a mild weather comp (that could be offset with lower O&M). We also see **AEE** as a significant miss, with a negative weather comp and the absence of a 1x favorable fuel recovery from 1Q15 as well as the loss of Noranda load this year. Look for a miss at **EXC** on POM merger transaction costs and a miss at **ETR** for unfavorable hedge accounting year-over-year comps (mark to market) and lower tax benefits.

## Our Top Picks Overall

**EIX:** Negative effect on ratebase from bonus depreciation completely offset by additional pole loading capex authorized in the last ratecase. Trades in-line despite above-average 7% ratebase growth with no equity through 2020 and continued cost savings between ratecases. Nascent Edison Energy upside to 10% of EIX (~\$0.40) over time. We also note that there is no requirement for any further response from the ALJ regarding SONGS, with possible significant recoveries from Mitsubishi in ongoing arbitration this year. Remains a positive estimate revision story coupled with diminishing SONGS risks.

**DUK:** DUK is preparing to sell its entire 4.3 GW Latin American generation portfolio. As such, we see the discount to peers as unwarranted, with DUK more likely to outperform in 2H16 as it joins the ranks of PPL among others to re-rate back to a 'pure play'. Reiterating 4%-6% EPS CAGR from '16-'20 but emphasizing 4%-5% from the "base plan" (~4% from 'core' utilities), which includes only ~0.5% load growth, flat non-rider O&M, and \$3B of discretionary capex to offset - \$2.5B bonus depreciation impact to ratebase. We believe upside to 5%-6% includes Piedmont acquisition, fleet & grid modernization, gas infrastructure, and more renewables. Bottom line, remains our favorite large-cap name to replace other perceived premium mega-cap utilities.

**POR:** New legislation just passed in Oregon presents the company with several \$B of capex opportunity through 2040 as the state builds wind (some in ratebase) to meet 50% renewables targets. Coal-power imports from Colstrip are set to stop by 2035 too. Admittedly, consternation around the Carty CCGT construction remains the risk point given focus on achieving the July deadline following handover from now bankrupt construction contractor Abiensa. A delay past July 31st could cause a need to file a ratecase in 2016 (instead of planned late-2018). Bottom line, we view the -8% relative underperformance in recent weeks adequately reflects what is principally a recovery timing issue and the discount vs. peers may provide a more attractive opportunity to invest for the long-term capex story.

**PPL:** We see PPL as one of the cleaner large cap regulated utilities with minimal headline exposure. The latest F/X and RPI trends for the U.K. are discouraging but this is countered by PPL having among the least exposure to a reduction in ratebase from the extension of bonus depreciation with ~50% of future capex targeting the U.K, with further capex investments expected with 1Q results – and further capex upside into future years with the PA-NY Compass project planning now under way. We see the opacity around 'Brexit ' in the near-term may provide some eventual opportunity.

**SRE:** We view this is a more attractive opportunity to accumulate one of our top picks with shares undervalued ~15% on the latest uncertainty over a possible slight downshift from best-in-class 11% earnings growth guidance at the upcoming Analyst Day in May, the pending General Ratecase decision, and the Aliso Canyon leak. We see continued underperformance as providing a more attractive opportunity for a key strategic pivot in strategy around its May Analyst Day, leveraging the balance sheet capacity otherwise allocated towards more LNG exports. We see meaningful DPS growth as a 'worst case' structural angle for shares.

# Interest Rate Views

## Regulated Valuations: Starting to look expensive again

Despite our positive capex outlook for the next few years – and in turn EPS revisions, the key question remains how far can regulated P/E multiples continue to run on a renewed 'lower for longer' rates thesis. While we remain broadly supportive of the sector, emphasizing our top picks are decisively regulated (AEP, DUK, PPL, DTE, and EIX), the question is whether the current 111% implied P/E vs S&P can continue upward to the high watermarks of 115-120% relative to the S&P (and how long it can maintain these heights). We still skew positively into 2H16, although less enthusiastically given the 10% outperformance of XLU vs SPX early into the year. We continue to note the backdrop of positive earnings contributing to wider sector outperformance, although mild weather should weigh on 1Q16. Looking towards 2H16, with CPP implementation and renewable policies particularly vulnerable to political will, the election cycle is likely to matter (*more* than past cycles).

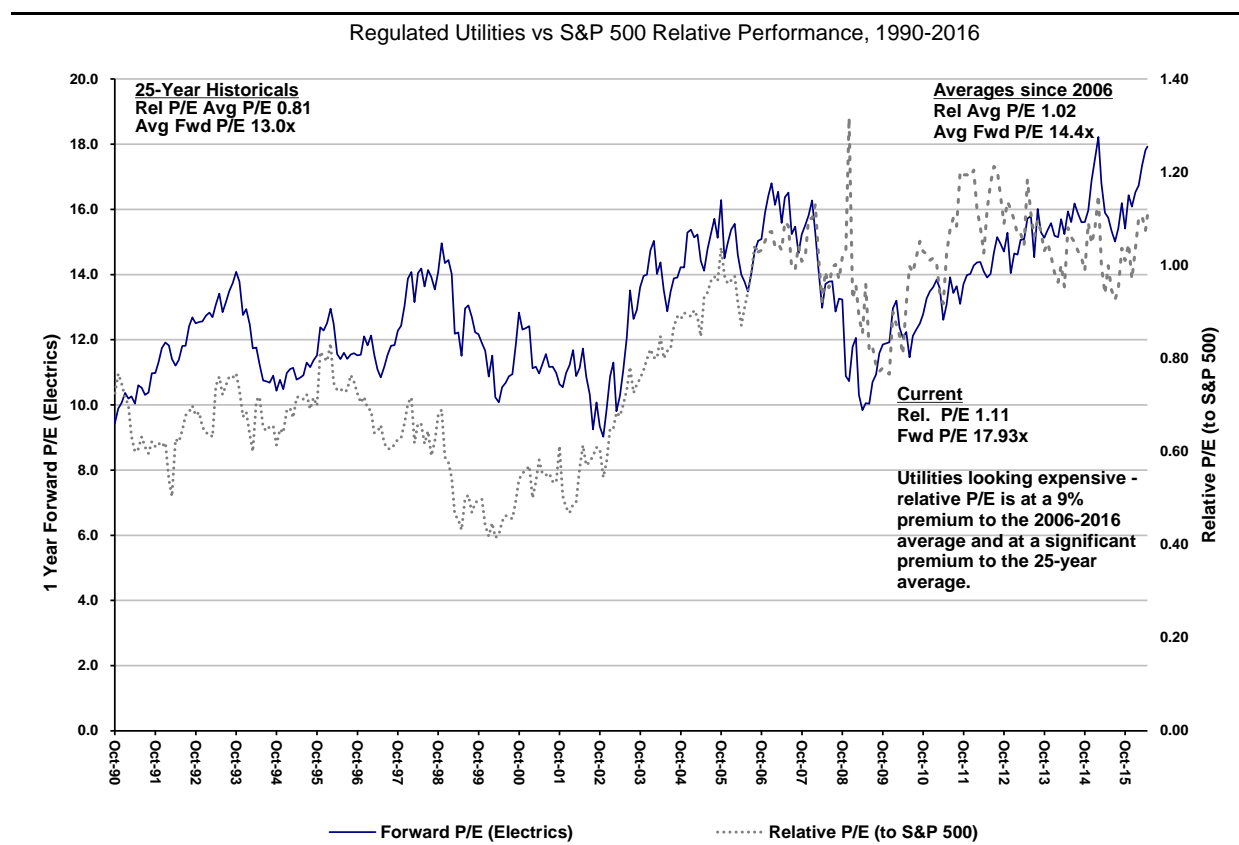
## Utility valuations nearing all-time highs vs the broader market

Although the general trend since Feb 2011 has been for regulated utilities to underperform the S&P 500, recent 20% outperformance since Dec 1, 2015 leaves the group trading at an 11% premium to the broader market (vs an average 2% over the past few years). Although not quite at peak valuations last seen in 2011 (a 20% premium P/E), we see shares trading at the higher-end of their recent forward P/E range at ~17.9x vs the 14.4x ten-year average. The move is not surprising given the Fed's more dovish actions of late and a flight to safety among larger energy volatility, but we believe this raises the near-term risk profile of investing in the space.

## Utilities stand in contrast to MLP, Power, and YieldCo underperformance

As we noted throughout 2H15, this also stands in stark contrast relative to the sharp pullback in more exposed equities like Power and YieldCos. We believe some of the positive outperformance of late is a re-entrenchment back to investments more consistent with many industry benchmarks. We emphasize protracted lower interest rates should enable some reinvigoration back into the YieldCo sector simply on a valuation argument premised on low discount rates. We're generally more constructive on power, with re-focusing on the coal-to-gas theme and suspect bottoming of power could yet be found around winter periods, when forward risk premiums on the most volatility period are fully removed. Further, we flag the divergence between capital-market dependent MLPs and utilities.

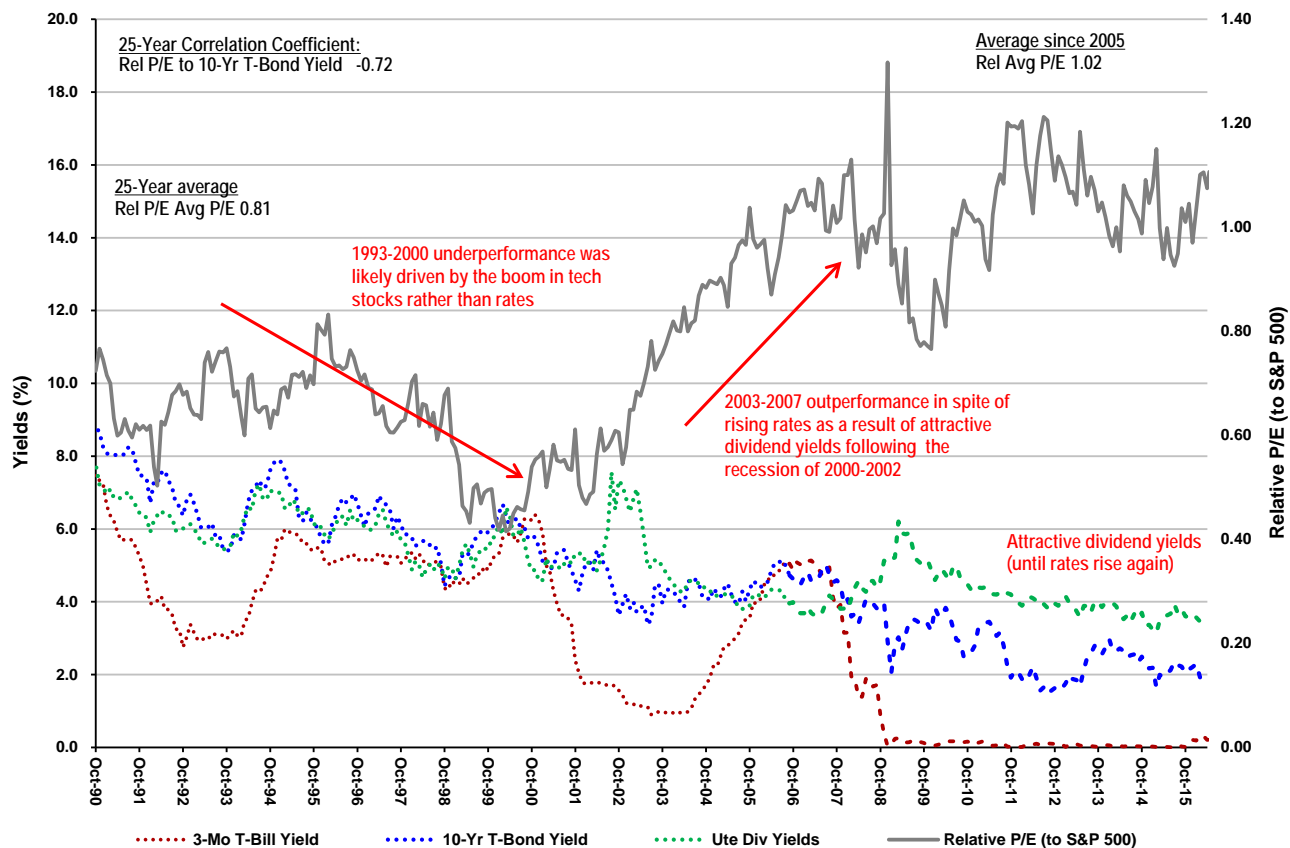
**Figure 3: Utility vs S&P 500 Relative Performance, 1990-2016**



Source: FactSet and UBS Estimates

As illustrated in the next chart, sustained low interest rates have kept utility P/E's generally aloft in recent years as the relative attractiveness of their dividend yields provides support.

Figure 4: Utility Relative P/E vs Note, Bond, and Dividend Yields, 1990-2016



Source: FactSet and UBS Estimates

## UBS House View Calls for Very Gradual Rise

While the focus in the near-term remains on further positive revisions to the short-term rates throughout 2016 (weighted toward 2H) and 2017, the question remains what the corresponding impact will be on the 10 Treasury bond, utility corporate bond indices, and ultimately utility equities. Despite the eventual threat of a material rise, we emphasize that rising near-term rates would probably not translate to a linear increase in the rest of the curve – rather a flattening of the yield curve appears more likely. The question to us remains whether any significant fed tightening can occur amidst an environment of global loosening, particularly with impacts on USD competitiveness and availability of credit. For a more detailed official UBS view, see [3/14/16 FOMC – the pause that refreshes?](#)

As we note in the table to the right, UBS is calling for the 10-yr to rise to 2.0% by yearend 2016 and to a 2.3% by yearend 2017. Based on the strong historical correlation between the 10 year Treasury yield and relative utility pricing (see charts below), this implies a relative utility P/E to the SPX P/E of **~1.03 by yearend 2016** and **~1.01 by yearend 2017**. Compared to the current 1.11, this further implies **-7% underperformance for regulated utilities vs the SPX through yearend 2016** and **-9.2% through yearend 2017 (an incremental -2% in 2017)**. Admittedly, this is a rough projection dependent on historical correlations that may not be fully realized given the wide spreads utility dividend yields currently enjoy vs government bonds. In other words, we believe any future

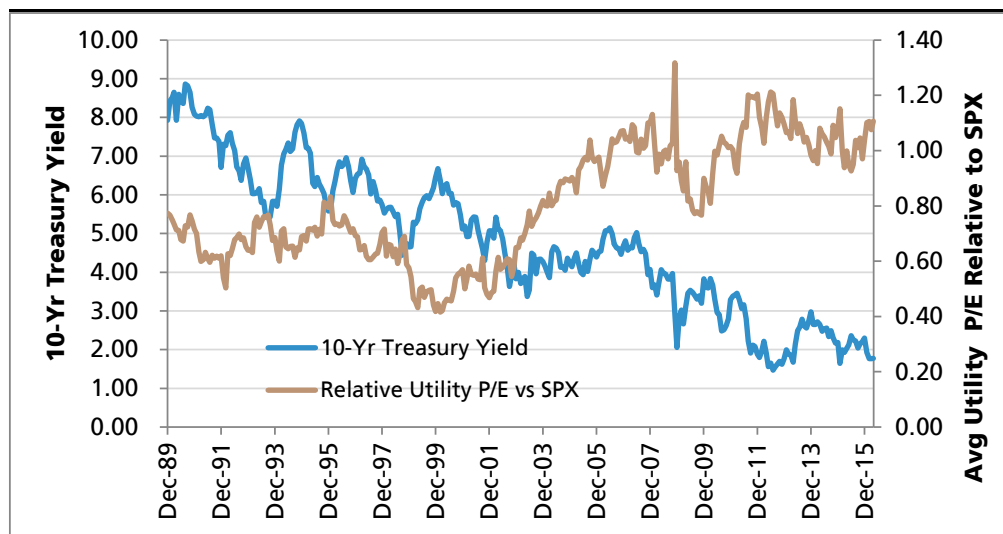
Figure 5: UBSe Rate & Yield Forecast (%), Dec 2014-Dec 2017E

Quarter	10 year bond yield (end period)	3 month Libor (end period)	Fed Funds Rate (end period)
Dec-14	2.17	0.26	0.13
Mar-15	1.94	0.27	0.13
Jun-15	2.35	0.28	0.13
Sep-15	2.06	0.33	0.13
Dec-15	2.27	0.61	0.38
Mar-16	1.89	0.61	0.38
Jun-16	1.92	0.61	0.38
Sep-16	1.96	1.13	0.63
Dec-16	2.00	1.38	0.88
Mar-17	2.08	1.63	1.13
Jun-17	2.15	1.88	1.38
Sep-17	2.23	2.13	1.63
Dec-17	2.30	2.38	1.88

Source: UBS Estimates

underperformance of utilities is likely to be tempered by dividend yield support until rates rise substantially.

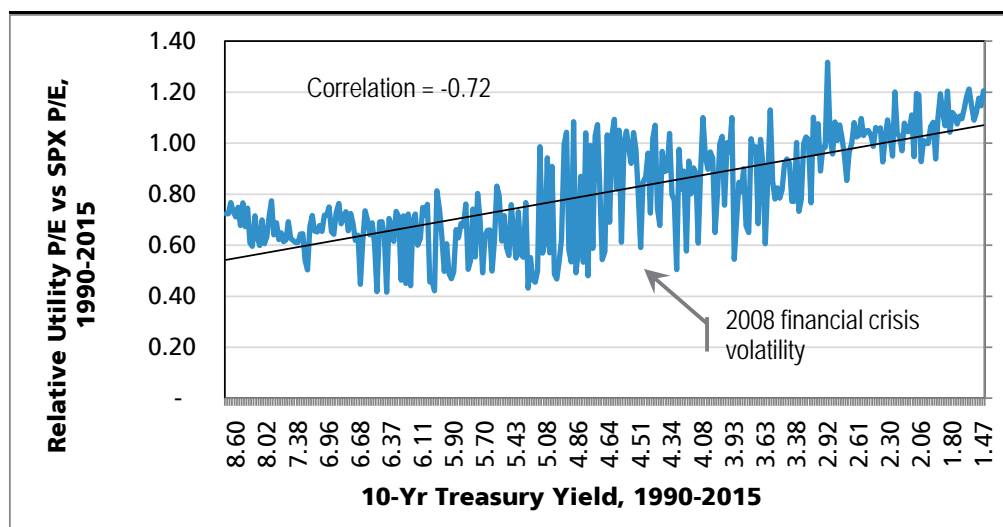
**Figure 6: Average Relative Utility P/E (to SPX P/E) vs 10-Year Treasury Yield, 1990-2016**



Source: FactSet

In the next table, we view the strong correlation between utility pricing and Treasury yields by taking the same data in the chart above and ranking it in order of yield (rather than a time sequence).

**Figure 7: Average Relative Utility P/E (to SPX P/E) vs 10-Year Treasury Yield, 1990-2016**



Source: FactSet

For more information, see our recent UBS macroeconomic notes:

- [4/19/16 March housing surprise on the downside](#)
- [4/15/16 Another 0.6% drop in industrial output](#)
- [4/15/16 What to watch in the week ahead](#)
- [4/14/16 Softer CPI, but inflation risks remain](#)
- [4/8/16 Is the Industrial Recession Really Over?](#)

## Regulated Utilities: Quite Toppish (again)

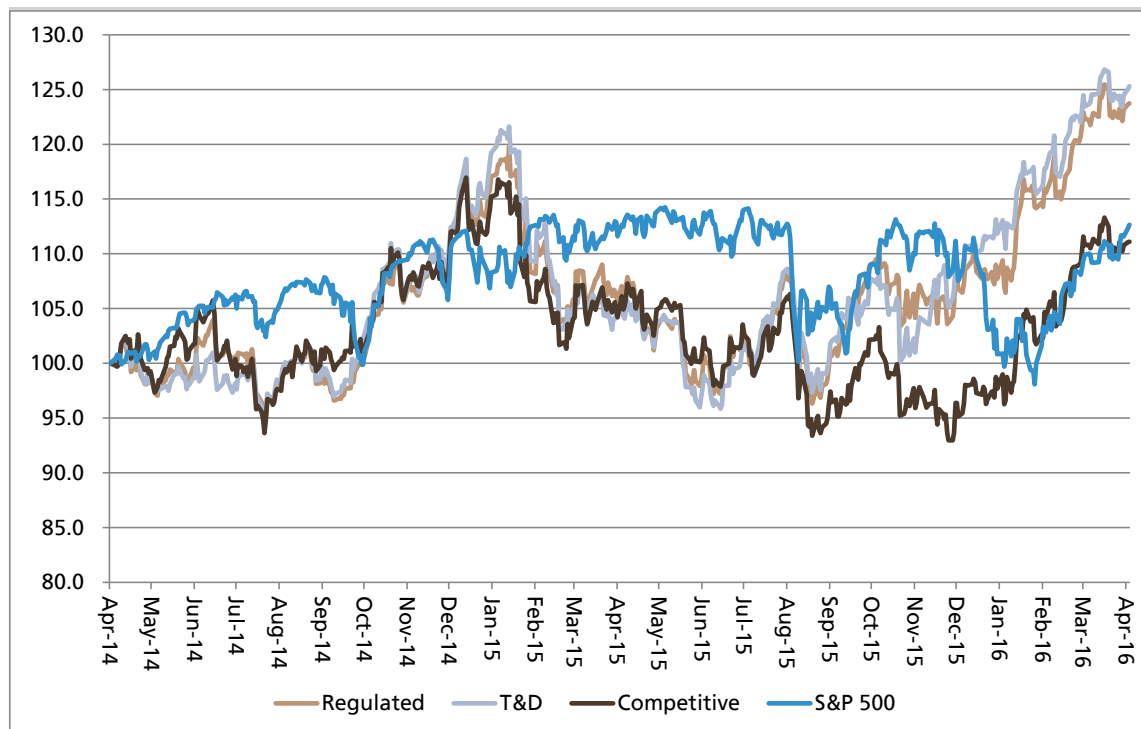
### How to position in a defensive market?

We're remain biased towards our large-cap names such as DUK, AEP, EIX, and NEE among others. We remain slightly *less* weighted towards our smid-cap favorites. However, we do see clear preferences emerging among our favorite regulated equities versus some of the more traditionally defensive names such as ConED (ED) and Xcel Energy (XEL). We see these latter companies as still vulnerable into 1Q results given below average growth (ED) and risks to the forward-looking capex and ratebase growth forecasts as a result of competition with 3<sup>rd</sup> party renewable developers (XEL).

### How do utilities stack up?

Below we show how the competitive and regulated sub sectors have performed over the past two years – T&D utilities have been the best performers over this period, with ED leading the outperformance.

**Figure 8: Utility sub-sector performance : Regulateds are leading the pack**



Source: Factset

## Regulatory Update

### Key Rate Cases to Watch:

Beyond the legislative efforts, we emphasize the following key cases as driving sentiment and equities.

**Figure 3: Select Pending Electric Rate Cases**

Company	Parent Company Ticker	State	Case Identification	Service	Rate Increase (\$M)	Return on Equity (%)	Action Likely By
Florida Power & Light Co.	NEE	Florida	D-160021-EI	Electric	1,337.7	11.50	12/31/2016
Pacific Gas and Electric Co.	PCG	California	A-13-12-012 (GT&S)	Natural Gas	532.0	NA	4/30/2016
Consolidated Edison Co. of NY	ED	New York	C-16-E-0060	Electric	482.0	9.75	12/31/2016
DTE Electric Co.	DTE	Michigan	C-U-18014	Electric	344.0	10.50	2/1/2017
Northern States Power Co. - MN	XEL	Minnesota	D-E-002/GR-15-826	Electric	297.1	10.00	6/1/2017
Pacific Gas and Electric Co.	PCG	California	A-15-09-001 (Elec)	Electric	270.5	NA	12/31/2016
Southern California Gas Co.	SRE	California	A-14-11-004	Natural Gas	234.1	NA	4/30/2016
Consumers Energy Co.	CMS	Michigan	C-U-17990	Electric	225.4	10.70	3/1/2017
DTE Gas Co.	DTE	Michigan	C-U-17999	Natural Gas	182.9	10.75	12/19/2016
Consolidated Edison Co. of NY	ED	New York	C-16-G-0061	Natural Gas	154.0	9.75	12/31/2016
Commonwealth Edison Co.	EXC	Illinois	D-16-0259	Electric	139.6	8.64	12/9/2016
Baltimore Gas and Electric Co.	EXC	Maryland	C-9406 (elec)	Electric	120.9	10.60	6/4/2016
Appalachian Power Co.	AEP	West Virginia	C-16-0239-E- ENEC	Electric	108.3	NA	6/30/2016
San Diego Gas & Electric Co.	SRE	California	A-14-11-003 (Elec)	Electric	91.9	NA	4/30/2016
Consumers Energy Co.	CMS	Michigan	C-U-17882	Natural Gas	84.7	10.70	7/18/2016
Public Service Co. of OK	AEP	Oklahoma	Ca-PUD201500208	Electric	84.4	10.50	4/30/2016
Atlantic City Electric Co.	EXC	New Jersey	D-ER-15xxxxx	Electric	84.4	10.60	12/22/2016
Baltimore Gas and Electric Co.	EXC	Maryland	C-9406 (gas)	Natural Gas	79.5	10.50	6/4/2016
Southwestern Public Service Co	XEL	Texas	D-45524	Electric	71.9	10.25	1/31/2017
Dayton Power and Light Co.	AES	Ohio	C-15-1830-EL-AIR	Electric	65.8	10.50	9/30/2016
Pacific Gas and Electric Co.	PCG	California	A-15-09-001 (Gas)	Natural Gas	62.6	NA	12/31/2016

Source: SNL Energy

Of these cases above we highlight several key points

- **PG&E:** Has several outstanding cases (GT&S, Electric, and Gas), amounting to nearly ~\$1 Bn/yr in annualized revenue hikes. We believe an ALJ proposal on the GT&S case could prove forthcoming in the near-term, although caution this has already been delayed (and expectations were for a ~Dec ALJ decision). This case remains critical not only to PG&E but also impacted IPPs such as DYN.
- **ConEd:** ConEd filed for \$482 million in electric rate increases based on a 9.75% ROE. Final decisions in this case are expected towards the end of 2016; the real question is not only where the authorized level will land, but to what extent can ED continue to over-earn at the top end of the band as it did last year? We note AGR recently guided to 8-10% EPS growth on the back of some degree of over-earning at its NY utilities.
- **SRE:** We continue to await a PD and subsequent decision from the CPUC on its pending SoCal and SDG&E rate cases, on which settlements have already been filed. While we had previously seen the cases as low profile, given the ongoing Aliso Canyon storage leak emphasis has refocused on this case. We continue to see the issues as relatively separate, with the Aliso Canyon issues addressed in subsequent OII proceedings (likely to be opened in the near-term). This remains the key overhang in shares today, risking a delay in the Analyst Day if not even a Proposed Decision (PD) is forthcoming by May (despite the lodged settlement already on the subject).
- **FP&L:** FP&L requested a four-year rate plan under which rates would increase by more than \$1.3 bn. The company supports an 11.50% return on equity on a \$33.9 bn rate base. The Commission is expected to issue a decision by year-end 2016.
- **CE:** CE filed a request for a \$225.4 million permanent rate increase premised upon a 10.7% ROE. The company cites new investments in the system's reliability, environmental compliance and technology enhancements as necessitating the request.
- **SO:** Will be coming with its latest rate case in Georgia as part of its ongoing process, alongside MS once the Kemper project reaches final in-service. Overall, when coupled with developments at Vogtle, we expect a relatively active docket in 2016.
- **EXC:** Looking for rate recovery at its recently acquired Pepco subsidiaries, particularly with no rate stay-out requirements after close, we expect filings in *all* jurisdictions. Historic cadence of rate cases has been every 2-years for these utilities. The question remains how much of an improvement can be achieved in these jurisdictions under EXC ownership; how close to its authorized ROE is *possible*?

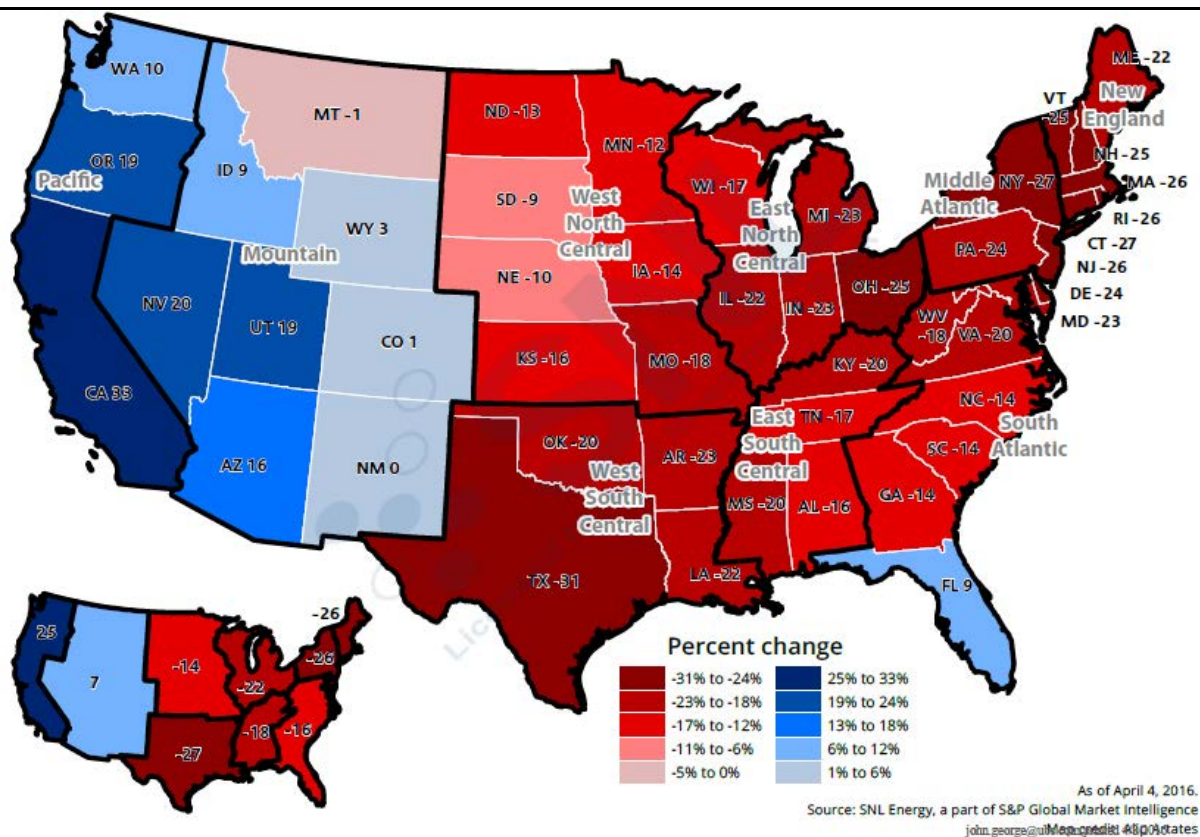
## **Recap and Preview of major M&A-related proceedings**

- **TE/EMA**: We continue to expect that the transaction will be completed as TE successfully navigated its own approval of NMGC with largely the same NM Commission. Key terms of the merger proceeding include an agreement to keep base rates the same at least until YE17, zero charges to ratepayers to recover acquisition premium costs, continuing \$4mn in annual bill reduction credit through mid-2018, and maintaining the 50% equity ratio until the next rate case.
- **NEE/HEI**: With the June 3<sup>rd</sup> deadline approaching after which either NEE or HE can walk away from the merger agreement, we see the current price for HE as indicating low expectation of the deal getting completed. The Governor has framed his opposition to NEE as "not a good fit" for the state's energy goals, despite NEE's much larger balance sheet and status as one of the largest renewable energy developers in North America.
- **SO/AGL Resources**: The companies cleared another hurdle in their GA-jurisdictional merger proceedings last week when the PSC unanimously approved the settlement. We continue to expect the companies will receive approval in the other jurisdictions. [Please read our recent SO note on this link](#)
- **DUK/PNY**: On March 14<sup>th</sup>, the Tennessee Regulatory Authority (TRA) approved the change of control leaving the NCUC as the last regulatory approval necessary to close the transaction. Management continues to believe a closing by YE16 is possible with hearings scheduled for July 18<sup>th</sup>. See our full [report here](#).
- **EDE/AQN**: EDE mgmt. mentioned all state filings related to the Algonquin deal have been submitted as of the end of March. AQN believes a January 2017 close is reasonable as they have secured C\$1.15B convertible debentures, and the only portion remaining with respect to financing the \$2.4B deal is the \$600M private placement.
- **ITC/Fortis**: Canadian utility Fortis announced plans to acquire ITC for \$6.9B of equity and the assumption of \$4.4B consolidated ITC debt that would ultimately create a ~\$30B EV utility. The formal acquisition applications will not be filed until the joint venture investment is in place but Fortis stated that it will file the applications "no later than 120-days from the time of the announcement" [February 9] which implies that the applications will be made by June 8<sup>th</sup>.
- **WR/AEE**: AEE has expressed interest in bidding for WR, as reported by Bloomberg. Following media reports, Westar has not issued a press release to confirm the sales process, which has been typical of other recent deals, including EDE and TE. Many companies that have struggled to meet earnings growth targets have opted for inorganic growth opportunities such as an acquisition in lieu of reducing earnings expectations.

## Weather: Starting 2016 with warm winter

The weather tells the story of 1Q16 with double-digit percentage point declines in heating degree days (HDD) versus a cold 1Q15 across the majority of the eastern United States. The combination of above-average HDDs during the winter of 2015 and below-average HDDs this past winter creates a challenging comparison for virtually all eastern utilities that are not fully decoupled from weather.

**Figure 9: Quarterly Weather Map: Cooling Degree Days 1Q16 vs 1Q15: State/Regional Perspective (% change)**



Source: SNL Energy

# Latest Thoughts on Power Markets

## PJM: How Low Will It Go?

With the PJM auction poised to begin on May 11<sup>th</sup> with results expected after-hours on May 24<sup>th</sup> we highlight key pivotal questions in the upcoming 2019/2020 Base Residual Auction (BRA).

### What is the forecasted clearing price? Expectations are moderating

Investor expectations for the 2019/2020 BRA have declined in recent months to the \$120-140/MW-day range following the negative demand forecasts revisions, the decline in auction outcomes in ISO-NE & MISO, and new build datapoints. We continue to project a steep drop from \$164.77 in last year's 2018/19 auction to \$140/MW-day for 2019/20, followed by an increase next year to \$170 for 2020/21. For once, we find ourselves at least at the midpoint if not the higher end of capacity expectations. That said, our figure could understate continued trends of new supply bringing us down up to a low case of \$130/MW-day. We see the bottom end of the 'consensus' range as quite unlikely. That said, base pricing trends could trend down substantially YoY to quite low levels.

Our \$140/MW-day estimate is seemingly at the top-end of buy-side expectations.

**Figure 10: Unchanged Supply/Demand Impacts for Pricing the 2019/20 and 2020/21 BRAs vs Actual Outcome of 2018/19 (~\$6 per GW change)**

Change in Forecast Pool Requirement (FPR) parameters	\$ /MW-day	
	MWs	Impact
Increase in Installed Reserve Margin 80 bps to 16.5%	+1,100	+\$6
Other adjustments to FPR	-430	-\$2
<b>Total impact on required MWs from higher FPR</b>	<b>+670</b>	<b>+\$3</b>

<b>Possible Supply Changes 2019/20 auction</b>		
Dominion's Greensville CCGT - online by 2019	+1,586	-\$8
New Gas Plant Proxy	+1,000	-\$5
Talen - Sapphire Portfolio in NJ (Partial Clearing)	+1,000	-\$5
<i>Maryland HAA Regs Take Effect Jan 1, 2020: Possible Compliance</i>		
Dickerson 1-3 (SNCR) - retire May 2019	-588	+\$3
Crane 1 (SNCR) - possible retire in 2020 under MD air regs	-190	+\$1
Crane 2 (SNCR) - possible retire in 2020 under MD air regs	-209	+\$1
Wagner 2 (SNCR) - retire June 2020	-136	+\$1
<b>Total 2019/20 supply impacts vs 2018/19 auction</b>	<b>+2,463</b>	<b>-\$13</b>
<b>Load growth 2018/19 to 2019/20</b>	<b>+1,490</b>	<b>+\$8</b>
<b>Extract (add back) supply-side EE that cleared 2018/19 from the load forecast</b>	<b>+1,247</b>	<b>+\$6</b>
<b>Reduced 2019 load forecast adjustments</b>	<b>-5,720</b>	<b>-\$30</b>
<b>Higher reserve margin requirement and FPR</b>	<b>+670</b>	<b>+\$3</b>
<b>Total 2019/20 impact vs \$165/MW-day 2018/19 BRA Outcome</b>	<b>-\$25</b>	<b>\$140</b>

<b>Incremental Supply Changes 2020/21 auction</b>		
Dropout of 25% of Base product Demand Response under 100% CP	-1,550	+\$9
Dropout of gas peakers under 100% CP	-5,000	+\$31
Placeholder for additional gas-fired gen	+2,000	-\$12
<b>Incremental 2020/21 impacts vs 2019/20</b>	<b>-4,550</b>	<b>+\$28</b>
<b>Incremental increase of 2021 load forecast from 2019</b>	<b>+400</b>	<b>+\$2</b>
<b>Incremental 2020/21 impact vs 2019/20 BRA Outcome</b>	<b>+30</b>	<b>\$170</b>

Source: UBS Estimates, PJM, Company Filings

## Will PJM add back to the load forecast EE that clears the auction as supply?

The key question remaining is the extent of positive adjustment to demand utilized in the Reliability Pricing Model to account for programmatic energy efficiency (EE) bidding in as supply; we continue to assume that this is about the same +1.3GW of EE that cleared 2018/19, which improves our forecast about \$6/MW-day.

## Development remains the real risk

We emphasize continued new build of generation despite the declining capacity price trend remains the focal point of debate among investors. While we understand some generators may not have cleared the auction last year due to late change in the collateral requirements, we could see hold-overs. Further with both sparks intact and interest rates low, the key pushback on new entry remains limitations for hedging and bank/institutional lending for new deals given cumulative exposures in the market. While we assume +1GW of merchant capacity as a placeholder, some IPPs suggest zero incremental generation could clear. We believe many underestimate the degree to which capacity slated to clear last year was *not* able to do so given the late adoption of CP rules, and implications on requirements allowing units to bid into the auction. We actually continue to believe more than *just one* new CCGT unit could clear. We further remind investors Dominion's VEPCO unit has clearly stated it intends to clear yet another regulated ratebase plant through the auction process.

Bottom line, we expect several GWs of new capacity, but still see a price trend towards the upper half of the price range.

## Will Maryland environmental regulations stand?

*It's unclear.* Among the points that investors and corporates point to is whether the existing regulations in Maryland will indeed go into effect as scheduled by January 1<sup>st</sup>, 2020. Further, the question is if any of the slated units we include will indeed retire or *rather* opt to convert to gas (particularly should shale gas supplies prove more abundant in the state). Should the rules slip, we see offsets potentially in other retirements from 'marginal' coal units in the region.

## How many are not clearing the auction already?

With 13GW failing to clear the latest auction, the question remains just how much 'clearing' capacity could yet fail to clear the CP auction. More importantly, how much of the 13GW failing to clear and/or base will eventually be able to comply – either from taking greater risk (Demand Response) or from investments in existing assets (dual fuel capabilities/new gas access).

## Limited renewable deployment prospects but still an impact

Taking solace in the deployment happening nationally, PJM appears the most 'resilient' to the prospects of more renewable generation additions. While further gas plant additions remain a risk, this should abate over the next several years. Overall, as we look towards an increasingly fossil vs. thermal world, we see this as the least exposed region to the coming wave given the more limited renewable resources to be found but that does not mean there is no impact. While there are still RPS mandates across a number of PJM member states, we believe deployment will prove delayed vs. other states given the use of largely market-based mechanisms to procure renewables thus far (as opposed to direct long-term contracting seen in other states). Behind-the-meter distributed solar was a key factor in the 3.5% reduction in the long-term load projection, which has been growing significantly over the last 2-4 yrs. PJM expects a net impact of about 300-

PJM is less exposed to renewables growth than markets like MISO and ERCOT.

600 MW through 2021, or a -0.4% effective load growth reduction; this could further accelerate following the investment tax credit (ITC) extension in December.

### **Zonal constraints appear to have eased for this auction**

Every zone has an increase in transfer limit vs transfer obligation, signaling an increased likelihood that all of PJM will receive the same price (non-binding); over the last auction DPL South had stood out as the only zone where this was not true. We also note the well-telegraphed reduction in load forecast across most of the RTO. We don't think the story here will focus on price separation for lack of transmission; rather generators will need to meaningfully shift their bidding strategies upwards to have zones (LDAs) clear at distinctly higher prices than the RTO region.

We continue to expect EMAAC to clear separately given the retirement of Oyster Creek; this could potentially be offset by the partial re-clearing of the Talen Sapphire portfolio, which did not clear in the last auction. price separation driven by needs to recover losses on nuclear plants as well as EME coal portfolio.

### **Ohio PPAs complicate issues but should *not* have a material impact on upcoming auction**

Although hotly debated we do not anticipate the recently approved Ohio PPAs awarded to FirstEnergy and American Electric Power as significantly impacting the upcoming 2019/2020 auction. We emphasize that FirstEnergy has indicated it was already bidding its each asset within its portfolio in a 'portfolio-like' manner above its specific unit costs, and reflecting the added risks of operations. We believe if the company is truly forced to bid at cost we could see prices decline under certain scenarios. FE has disclosed a proportion of each plant previously not cleared as part of this bidding approach in past auctions. Even assuming a 600MW impact (6GW \* 10% 'uncleared' previous capacity = ~600 MWs, or ~\$4-5/MW-day). We think it's a low immediate impact; it is more about the signal.

We understand that FERC could be poised to rule on the pending complaint on the FE and AEP affiliate waivers (which would implement the PPA structures) *prior* to the auction start, providing all participants visibility. The auction is slated to start on May 11<sup>th</sup> suggesting developments could come in the near term. We remain concerned that not only could FERC opt to remove its waiver, but the subsequent review could prove problematic to both. We emphasize FE is already organizing itself around an even more expansion re-regulation bill in Ohio next year if unsuccessful.

### **Are other restructured states going to follow Ohio? We do not expect them to.**

We do not see any other states immediately following the example of Ohio; rather, Illinois' own efforts in PJM will be legislative and attempting to save nuclear plants, rather than a return to a cost-of-service approach. Also at the core of any argument for FERC to intervene is the precedent established on future efforts by states to *begin* to re-regulate. The industry overall appears to be heading in this direction.

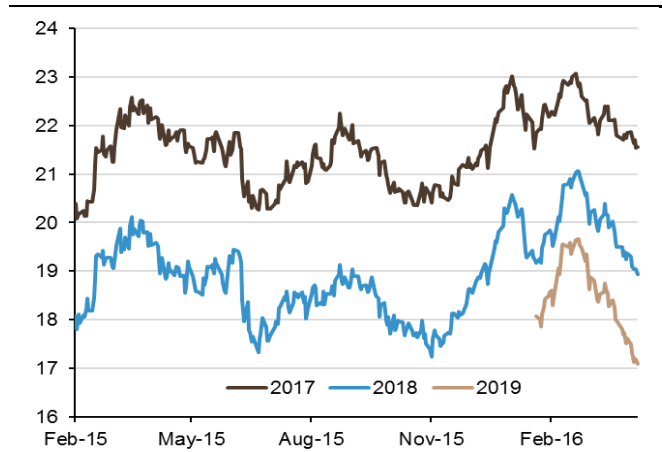
**We continue to expect some price separation, but rather than being this 'constrained' due to the typical CETO/CETL ratios, increasingly binding prices will be due to substantially greater bidding latitude as a result of the PJM reforms instituted last year.**

## Sparks pulling back as new entry concerns more front and center

Spreads retreated during 1Q16 but this essentially just reversed some of the gains from 4Q15 as gas and power have generally moved in tandem. This is yet another example of how gas price expectations, particularly winter premiums expectations drive overall sparks. ATC Power has recovered as of late but the overwhelming trend continues to be negative.

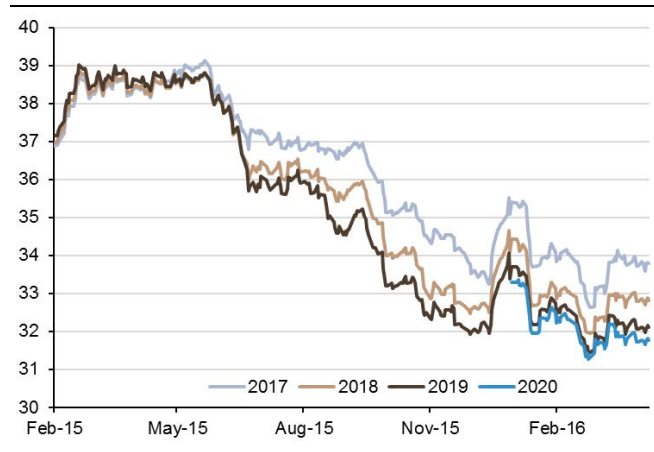
**We flag sparks have trended down despite resilient power prices ... offsetting the gains**

**Figure 11: PJM Spark Spreads @ 7.2 HR (\$/MWh)**



Source: Platts and UBS estimates

**Figure 12: PJM ATC Power Prices (\$/MWh)**

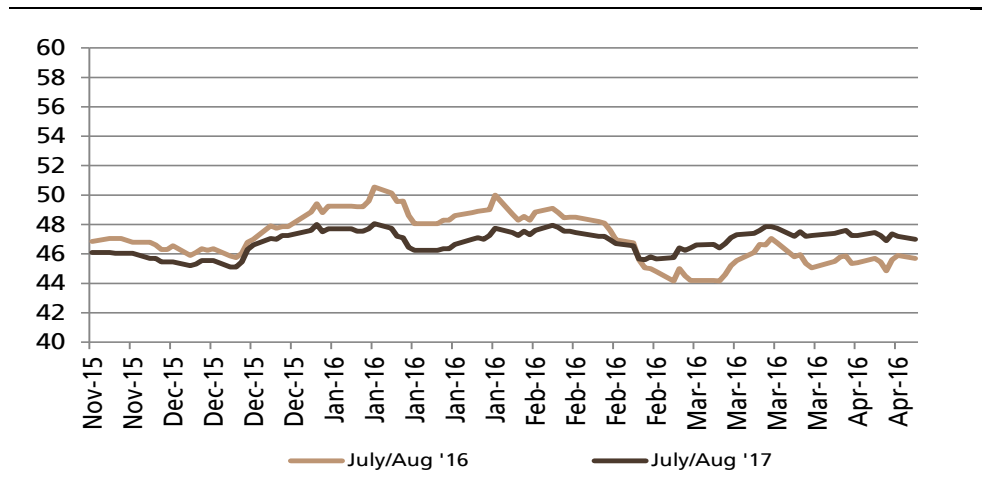


Source: Platts and UBS estimates

## Summer forwards are little changed in recent months

Previously 2016 was trading at a premium to 2017 but that dynamic has reversed in February. Overall, summer remains largely unchanged; we expect less volatility under the new Capacity Performance (CP) regime.

**Figure 13: Recent PJM Summer Forward Trends: Coming Back a Bit (\$/MWh)**

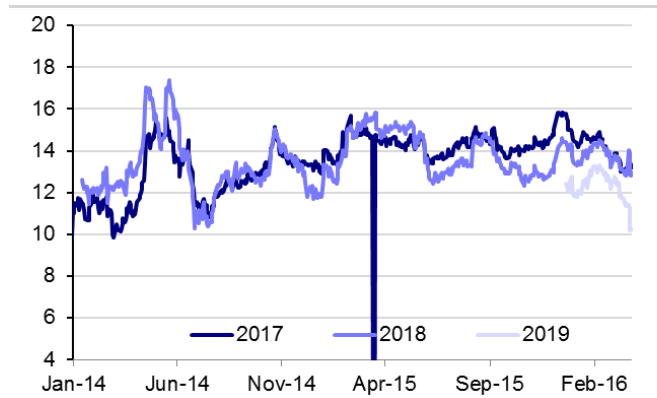


Source: Platts

## How do NI Hub (Chicago) price trends look?

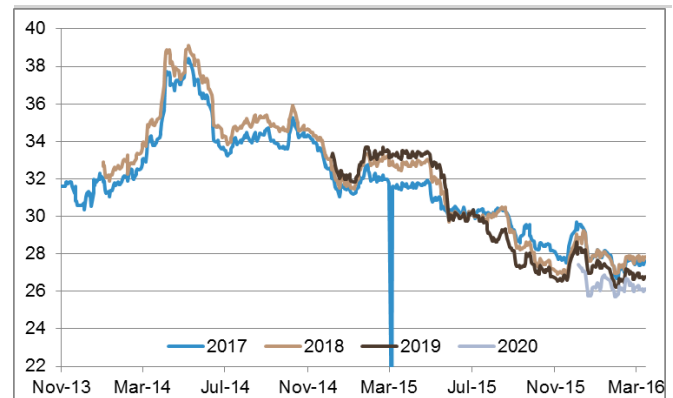
Although the trend has been overwhelmingly negative we have seen ATC prices stabilize between \$26-\$28/MWh. Prices remain below levels needed to support either nuclear generators or new build and the question is whether legislation will be approved to improve the prospects. Illinois will be a key battleground as Exelon has been vocal in stating it could begin retiring its nuclear assets in the state without legislative support. We look for any legislative deal that supports the Northern Illinois nuclear portfolio to have a corresponding program to support Southern Illinois coal plants. We see pressure mounting here with more retirements poised to be announced on both sides. More to the point, following the latest PTC extensions we could yet see more wind projects announced.

**Figure 14: NI Hub Spark Spreads @ 7.2 HR (\$/MWh)**



Source: Platts and UBS estimates

**Figure 15: NI Hub ATC Power Prices (\$/MWh)**



Source: Platts and UBS estimates

*For further background we include links to recent reports below:*

[4/1/2016: Comparing the PJM Solar Markets](#)

[3/28/16 Getting MOPRized](#)

[2/3/16: PJM: Little Changed for the Auction](#)

[2/2/16: PJM's Ohio Conundrum](#)

[1/4/16: PJM: Tweaking Up Our Outlook](#)

[12/24/15: PJM: Accentuating the Positive](#)

[12/17/15: PJM: Driving a Lower Load Forecast](#)

[12/14/15: PJM Unloaded](#)

## ERCOT: Texas Tidal Wave of Air Regs

### Assessing the State of the Texas Power Play – Timeline for retirements is key

We conducted our latest deep-dive into the viability of the state's coal portfolio, seeing nearly all of the state's merchant plants struggling to generate positive FCF in the current power price environment. With at least three waves of environmental regulations potentially impacting the state's portfolio (even prior to the Clean Power Plan), we see limited viability for a bulk of the ~18GW of TX coal (nearly a quarter of the state's 2014A generation portfolio). Of this ~10GWs need to reduce emissions by ~80%+ to comply with the Regional Haze (RH) regulations. With unscrubbed coal plants facing significant compliance costs (potentially hundreds of millions) we believe it is inevitable that several of the states' largest coal assets could opt to retire. That said, the key question remains when they will make a decision. With coal largely uneconomic today we would expect more retirements but generators are ascribing to game theory and are looking to be the 'last man standing' For example, NRG has pointing at other unscrubbed plants that it believes have more significant environmental requirements than its own fleet. For instance, DYN expressed little willingness to maintain the Coletto Creek coal plant given its smaller size (635MW) and potential exposure to future environmental regulations. Facing losses at this coal plant we see DYN as incentivized to shut the asset given its 4GW of other newly acquired ERCOT assets.

### But timing is of the essence here – when will coal finally give it up? 2017E.

Based upon conversations with industry experts in Texas air quality regulations and precedent for similar cases we see an increasing potential for a stay in the implementation of the RH regulations. If a stay is granted this could delay the compliance decision for assets to 2017 from 2016 but compliance would still be in the ~2019-2021 timeframe. The bulk of recent appeals to EPA's imposition of Regional Haze regulations have ultimately been upheld by the judicial system but a delay in timing could delay retirement decisions. While plants could well announce further mothballing as soon as this Fall given the current state of the market, formal retirement decisions could well be delayed out a year until firm clarity is received on the RH regulations. Timing of the ongoing EFH bankruptcy could also prove an important indicator of retirement timeline.

### No one is winning in Texas – except Calpine: Reiterate CPN as our clear top pick

What is increasingly clear is most IPPs are actually losing cash/close to break-even in operating their physical assets (ex-Retail), including NRG, EFH (using their previous disclosures), TLN (gas portfolio), and DYN (Engie). Rather, power hedges and retail enable positive overall cash flows for NRG and EFH. We believe the lone winner who generates meaningful cash flow today from its portfolio is Calpine—and more importantly – the player with staying power given the level of power remains CPN. We see EXC's modest position in the state as also a stable small piece of this story, but largely leveraged via its ExGen Texas financing. We are refining our Texas thesis to reiterate not only our preference for this market, but we see Calpine as uniquely positioned to benefit from this trend given limited compliance capex relative to peers.

Any way the regulations get cut, we see the timeline as pointing to as early as ~2019, but more likely in the 2020-2021 timeframe for Regional Haze.

Will investments be made to retrofit existing scrubbers? We doubt it.

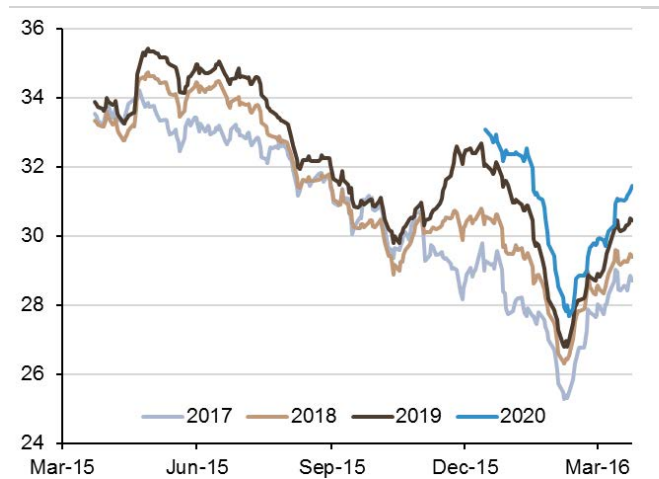
Amidst the particularly high cost of capital implied by current equity valuations, we see limited palatability to investing in negative FCF assets, even if modest retrofits are required given the weak resulting IRRs with upfront negative cash flows.

## Even nukes should be included in this analysis.

Amidst our focus on the portfolios of NRG, we note the nuclear plants merit attention. We believe NRG's two unit site at the South Texas Project (STP) would appear to risk have a negative FCF profile. Based on NEI disclosures the average US nuclear unit had an all-in cost of \$36/MWh in 2014 with first quartile units closer to \$29/MWh. As shown in the left Figure below, ERCOT-Houston ATC power is in the ~\$27-\$29/MWh range indicating that even with an efficient cost structure Texas power plants are likely struggling to generate positive free cash flow.

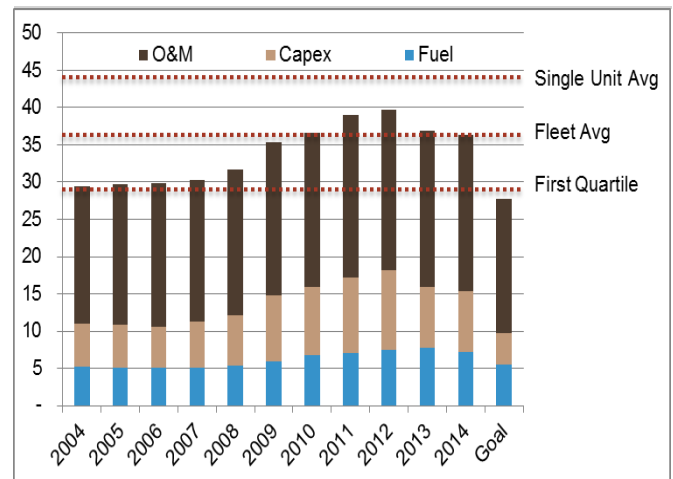
**Nuclear assets in TX appear to be operating near break-even, or potentially generating losses when including nuclear fuel.**

**Figure 16: ERCOT-Houston ATC Power Prices(\$/MWh)**



Source: Platts

**Figure 17: Historical & Target All-In Nuclear Costs (\$/MWh)**



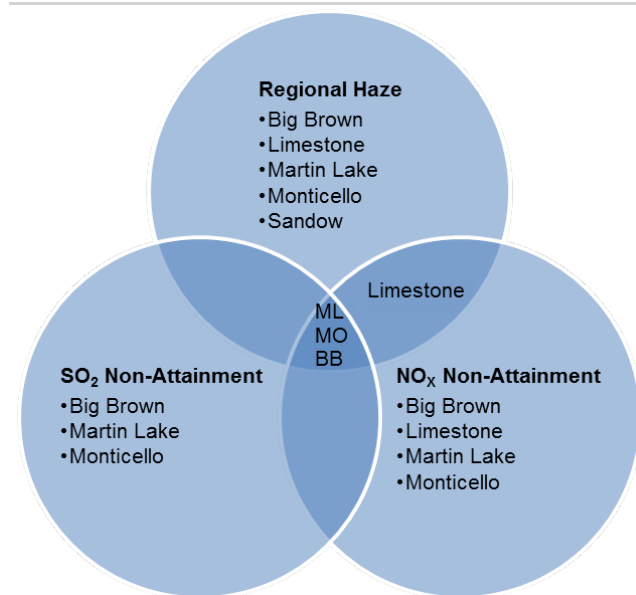
Source: Nuclear Energy Institute

## What are the regs on the table? There are three separate paths.

The primary regulation driving compliance is the recent finalization of the EPA's Regional Haze (RH) regulations on Texas in January (imposed on the state by the EPA using a Federal Implementation Plan, FIP, after rejections of the state's own State Implementation Plan, SIP). We note this regulation would allow for coal plants with existing scrubbers 3-years to retrofit while those without any scrubber retrofits would be afforded a 5-year period to reach compliance, with the clock ticking as of this January (assuming no stay). While Haze regulations in other states have principally targeted NO<sub>x</sub> emissions, in this particular instance the regulations are focused on reducing SO<sub>2</sub> emissions – and have specific targets. This is the most encompassing of the three standards with respect to plants impacted.

**In addition we highlight that there are additional local rules which could further pressure plants including Monticello, Martin Lake, and Big Brown**

**Figure 18: Texas Environmental Regulations**



Source: EPA, SNL Energy, Sierra Club, and UBS Estimates, Company Filings

## Renewables threaten the recovery

We see the declining cost of utility-scale solar as among the greatest risks to the timeline in the recovery in this market. Just as soon as the outlook for coal retirements and limited new gas could look bright in 2017, we expect to see more 'merchant' solar (10-year financial swap deals) in the 2018 or 2019 timeframe in this lower-cost market. We estimate high \$30/MWh peak prices appear to potentially support entry of projects (a level off which forwards are currently not far off). We look to an updated solar cost trajectory roadmap to be released at FirstSolar's upcoming April 5th Analyst Day in NYC. We believe all-in pricing could trend to shy of \$1/W by later in the decade (ex-margin), suggesting all-in projects could be sold in the \$1.20-1.30/W ballpark. Recall FSLR was the first to development merchant solar in the state, with its more 'experimental' investments at the Barilla plant (30MWs).

### Where are ERCOT power prices capped? At the cost of entry for new renewables.

More structurally, we perceive growing fears over concerns that Texas power prices have a de-facto cap tied to the price at which renewables can 'enter' the market. We see this as limiting improvement prospects for both off- and on-peak prices. While gas plant additions remain a relevant factor with a litany of sites under development already, some of which have contracts already in hand, including Brownsville, with 200MWs of contracted output to the local utility.

### No more transmission for now.

We note limited incremental new transmission plans for either the Panhandle region (PREZ) or West Texas (for contemplated solar build) to accommodate the continued build of renewables. Following the success of the original CREZ transmission lines (with almost all of its contemplated 18GW of capacity used by incremental renewables since its construction), the question has been whether the state would pursue any further large-scale efforts. While in Texas much of the expansion costs for generators is paid for by the utility, we note the limit on

**But when will the renewables hit (again)? Focus on FSLR and April Analyst Day**

**Is it wind or solar? Unclear, but both pose a potential risk.**

transmission capacity would appear to place a cap on development across this portion of the state, with a focus for new wind turning towards ERCOT-South particularly given its more on-peak orientation.

#### **But wait, where could we see more transmission? Around retirements.**

We also met with CNP management in Houston who described potential future transmission investments to backstop potential coal and steam-based gas plant retirements in the state. For instance we note NRG recently mothballed indefinitely another gas-based steamer unit in the region, a leading indicator towards a permanent retirement.

#### **What else is on the Texas radar screen – retail migration risk looms large**

Among the last points worth mentioning in the context of any Texas-led IPP recovery is the risk around retail migration. While this has historically been a risk, we see this as a particularly clear risk given the meaningfully above nature of many incumbent residential contracts. Most notably, we believe the risk pertains to the potential high correlation potential should customers en masse ‘find’ the option to shop appealing. We note both NRG and EFH continue to garner the bulk of their EBITDA and FCF from this business. We also note migration risk remains meaningful risk for EXC too in other states, where it is among the largest providers of load-following electricity (and hence implicitly exposed to migration risks too albeit in a less extreme sense given the more at ‘market’ or ‘lagging’ nature of these contracts).

[Further details are available at ofgem’s switching program site here.](#)

[Additionally, the latest on Ofgem and the CMA’s competition assessment are here.](#)

*For further background we include links to recent reports below:*

[ERCOT: Ever More Hazed and Confused](#)

[Riding the Commodity Bull in Texas](#)

[ERCOT: A Solar Eclipse?](#)

[Merchant Solar Arrives in Texas](#)

[Taxless Tieups in Texas](#)

[Reading the Tea Leaves in Texas Transmission](#)

[Putting a Texan Spin on the Power Outlook](#)

[Texas: Hazed and Confused](#) [Regional Haze regulations]

[Sunrise in Texas](#)

[Texas: New Supply Keeps Coming](#)

[Lone Star State Continues to Shine](#)

#### **Why do we emphasize this now?**

**We note the subject of retail switching continues to garner disproportionate headlines in the UK as regulators there appear keen to encourage accelerated customer switching. The Competition and Markets Authority (CMA) working with the UK energy regulator ofgem have been investigating the retail energy market to encourage customers to switch providers. One idea discussed was a transitional safeguard tariff to encourage engagement in the retail market.**

## MISO: Riding the Roller Coaster

### MISO capacity auction slumps ~50% YoY but still beats expectations

In the MISO 2016/2017 auction the key zones 2-7 (Illinois and Michigan are the primary investor focus) cleared at \$72/MW-day, down from \$150/MW-day in the prior year's auction but the result is modestly ahead of UBSe (\$50/MW-day) and meaningfully ahead of even lower Street expectations. The auction cleared in a highly-sensitive portion of the demand curve and a +/- ~185MW change in capacity was the difference between ~\$25/MW-day and \$110/MW-day. The MISO auction outcome is most relevant for Dynegy and Exelon but as we discuss next it is far less important with companies increasingly transacting with municipalities and retailers outside of the construct. A surprise beneficiary in the auction is CMS with Michigan Zone 7 prices jumping to \$72/MW-day from \$3.48/MW-day previously. CMS has 10-25% capacity available for 2016-2017 so the EPS benefit is de-minimus today but could be \$0.05/sh in 2018+.

### How important is the auction? Not a material driver given the bilaterals

Going into the auction Dynegy had already contracted for 3,920MW versus 2,334MW in the prior year's auction as management continues to reduce its reliance on the unpredictable MISO auction. Management subsequently disclosed that it did not clear any assets in the auction; this was light of our expectations (below-200MW cleared UBSe) but this was not surprising based upon our analysis of prior bidding behavior by market participants and commentary from management following our trip.

### Retirements still coming for both DYN and EXC: not high enough

Although the auction surpassed our estimates, the ~50% decline versus the prior year will significantly pressure merchant generators in the Illinois region, notably Dynegy and Exelon, and we anticipate both companies to announce asset retirements based on the auction outcome. For Exelon, management confirmed that it cleared the 2016/2017 auction but that it was still free cash flow negative. We expect a formal retirement announcement in September to take effect in Spring 2017. At Dynegy the IPH assets are at the most risk, specifically the higher-cost Newton unit (1.2GW).

Further details about potential retirements are available in the Dynegy and Exelon sections of the note below.

Figure 19: MISO Capacity Auction Snapshot

MISO Local Resource Zone	Zone 1 MN, ND, Western WI	Zone 2 Eastern WI, Upper MI	Zone 3 IA	Zone 4 IL	Zone 5 MO	Zone 6 IN, KY	Zone 7 MI	Zone 8 AR	Zone 9 LA, TX	Zone 10 MS
2014-2015 ACP (\$/MW-d)	\$3.29	\$16.75	\$16.75	\$16.75	\$16.75	\$16.75	\$16.75	\$16.44	\$16.44	N/A
2015-2016 ACP (\$/MW-d)	\$3.48	\$3.48	\$3.48	\$150.00	\$3.48	\$3.48	\$3.48	\$3.29	\$3.29	N/A
2016-2017 ACP (\$/MW-d)	\$19.72	\$72.00	\$72.00	\$72.00	\$72.00	\$72.00	\$72.00	\$2.99	\$2.99	\$2.99
2016-2017 ZRC Offer Cleared	4,522	2,840	9,636	8,242	7,927	14,060	20,141	9,676	17,934	4,511
2016-2017 Total Committed	18,775	14,903	10,138	9,152	7,927	18,398	21,534	9,995	18,511	6,151
2016-2017 FRAP (Delta)	(14,253)	(12,063)	(502)	(910)	-	(4,338)	(1,393)	(319)	(577)	(1,640)
2016-2017 Conduct Threshold	\$25.80	\$26.06	\$25.52	\$25.93	\$26.42	\$25.85	\$25.98	\$24.76	\$25.12	\$24.61
2016-2017 CONE	\$258.00	\$260.58	\$255.15	\$259.26	\$264.19	\$258.47	\$259.81	\$247.56	\$251.21	\$246.05

Source: MISO | ACP = Auction Clearing Price; ZRC = Zonal Resource Credits; FRAP = Fixed Resource Adequacy Plan; CONE = Cost of New Entry

## Distilling Last Year's Supply Curve for Clues

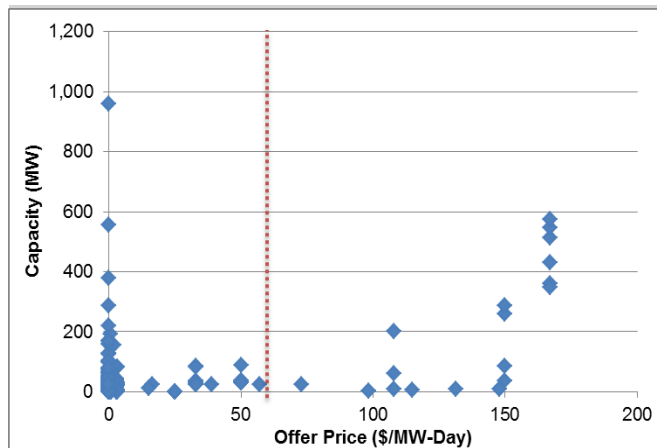
Below we show the offer price (\$/MW-day) relative to segment offer capacity (MW) for the 2015-2016 MISO auction showing where individual units bid in the previous auction. We have imposed the \$72/MW-day clearing price for both zones 4 and 7 over the data to show which units that cleared in the previous auction would not have cleared in the 2016-2017 auction assuming the same bidding behavior.

In the 2015-2016 auction for Zone 4 there were four market participants who bid over \$33/MW-day with average offer prices of \$144 (2,560MW), \$159 (1,151MW), \$87 (126MW), and \$40 (695MW). The market participant who bid 1,151MW at \$159/MW-day also interestingly bid \$0/MW-day for a separate 1,709MW which included one 958MW plant (the top left datapoint in the IL figure below).

Exelon commented last auction that it has historically bid in its 1,069MW Clinton nuclear plant as a price taker and in the 2015-2016 auction it did execute bilateral contracts reducing the amount of capacity available to bid.

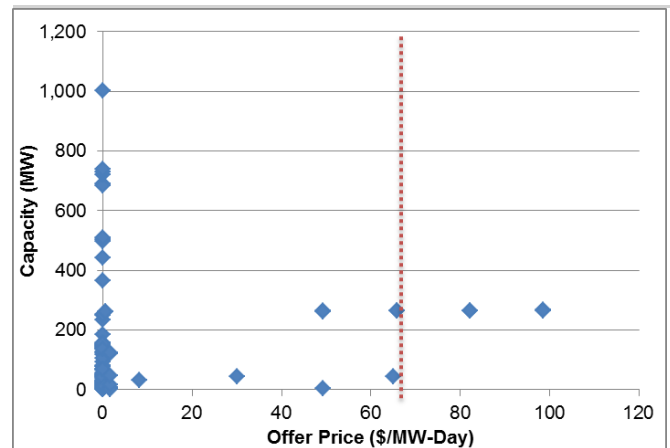
**What can the 2015-2016 MISO auction teach us about the current 2016-2017 auction?**

**Figure 20: IL Zone 4 2015-2016 Bidding Data**



Source: MISO

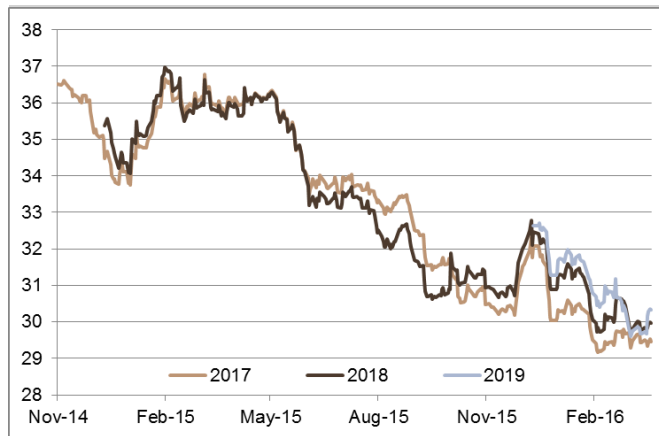
**Figure 21: MI Zone 7 2015-2016 Bidding Data**



Source: MISO

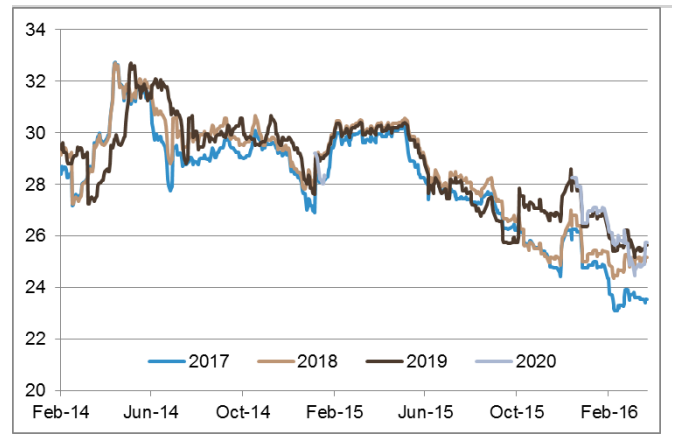
In Michigan there was one asset owner who bid in 2,644MW for 2015-2016 at prices ranging from \$1/MW-day to \$99/MW-day and only cleared 525MW at \$3.48/MW-day; this was one of the few market participants to not bid in \$0/MW-day. For example one market participant bid 10,953MW at \$0/MW-day, presumably a regulated entity. *For more supply curve information please see [here](#).*

**Figure 22: Indy Hub ATC Power Prices (\$/MWh)**



Source: Platts

**Figure 23: Indy Hub Offpeak Power Prices (\$/MWh)**



Source: Platts

*For further background we include links to recent reports below:*

[4/15/16 Riding the MISO Roller Coaster](#)

[4/13/16 A Chilly Reality for MISO Auction](#)

[3/21/16 MISO Moderation](#)

[1/6/16 MISO: Served Scrambled](#)

[12/23/15 MISO Transmission Wins Round One](#)

## New England: Dousing the Grid

### The Massachusetts legislation – really about Hydro

Following the reintroduction of Senate Bill 1965, feedback from industry sources indicates a strong possibility for legislation in MA this Summer that will include upwards of ~18TWh of contracting under an expanded Clean Energy RFP seeking low carbon resources to meet the states' Global Warming Solutions Act targets, given the need to address solar caps in the state. In our recent meeting with Avangrid (AGR), management framed the prospects for this legislation as really about hydro, more so than the ongoing RFP across the three-states, which would appear focused on more conventional resources. We believe this would explain ES' decision to pursue the New York export project into New England. AGR appears keen to compete with ES on the export avenue with its own Canadian interconnection itself. While a modest investment to interconnect its Northern Maine wind projects into Canada, this remains pending an RFP to do so from New England to pursue the project. Expect this to become a more fully defined procurement project in the coming months.

### Selections could be coming soon in Three-State Clean Energy RFP

Proposals were submitted on Jan 28, with selection of winning projects from 4/26 through 7/26. The RFP is a joint proposal from MA, CT, and RI for 5TWhs of carbon-free renewables and hydroelectric energy, with winning contracts submitted for regulatory approvals, expected in 'Summer'. ES is participating with both the Northern Pass and [Clean Energy Connect](#) projects.

### New generation are gas fired-units: who and what got selected?

FCA 10 attracted slightly over 1,400 megawatts of new generation; the new power plants were the 333MWs simple cycle GT Canal 3 unit by NRG in Southeastern Massachusetts, the 485MW CC Burrville Energy Center at Rhode Island by Invenergy (seemingly only one of two units contemplated cleared), and the 484 megawatt Bridgeport 6 CC unit in Connecticut by PSEG. Each of these generators is primarily gas fired, but is expected to be dual fuel capable with oil (given NE's often constrained winter gas pipelines, and also our pay per performance construct). We emphasize the willingness to participate is part of an observed wider trend of discounting the recent high risk premiums ascribed with the higher penalties under the Pay-for-Performance regimes.

### Initial thoughts on FCA #11: A tad more of everything... keeps us flattish

We believe the outlook will prove relatively flat YoY as we look towards the next auction for the 2020/2021 period. While admittedly large-scale hydro is indeed a risk for this delivery year, we believe any meaningful import projects would be mitigated. Rather, the key puts and takes relate to: 1) the existing 383MW Bridgeport Harbor coal unit retiring; the latest deal with the city would require its auction for FCA#12; 2) the future of the two other units at the NRG Canal site totalling 1.1GW. The capacity economics today should continue to support the site, particularly given the greater ability to amortize fixed costs across a third new unit. Lastly, we expect continued growth in renewables – both utility scale from ongoing state-wide RFPs (albeit with a moderated impact given limited capacity value) as well as from a further moderation in demand forecast given extended impact of solar rooftop with the ITC extension. Lastly, with Invenergy having seemingly only cleared one of the two CCGT trains at the site, further new

Watch for efforts on an omnibus energy bill following the recent successful passage of a solar net metering cap increase. We understand this remains a top priority of Governor Baker to pass a bill that would call for the procurement of large-scale hydro and offshore wind.

Irrespective, into the June expiration of the session this remains a unique risk for IPPs, and a key potential positive for ES

Retirements are key uncertainty into later auctions

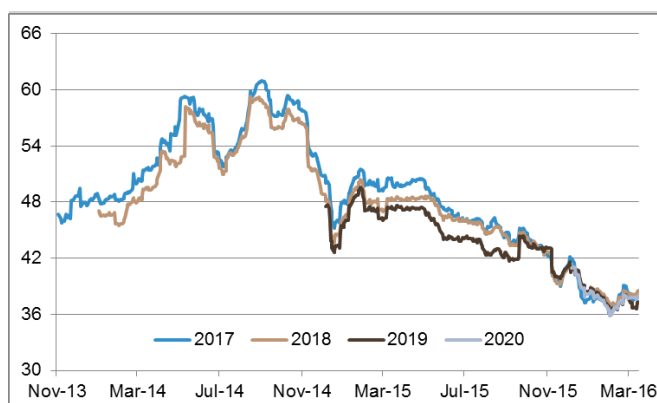
From the point of view of bidding strategies, we note that there is a de-facto floor in the auction at \$5.50/kW-mo, where generators can opt no longer to participate using dynamic delisting – this provides some more limited downside to where prices are today. We don't expect prices to head to the floor from here.

merchant capacity remains a clear risk; we emphasize the total ~7GWs that bid in will largely remain on the sidelines awaiting another 'bite at the apple'; lastly the threat of new imports remains another angle (aside Canadian Hydro) with the likes of the Roseton peaker from New York among other resource export attempts (such as the ES Clean Energy Connect), threatening to drive more of an 'equilibrium' between these two capacity constructs.

### Where will spark spreads trend? Cheap gas offset by even cheaper renewables

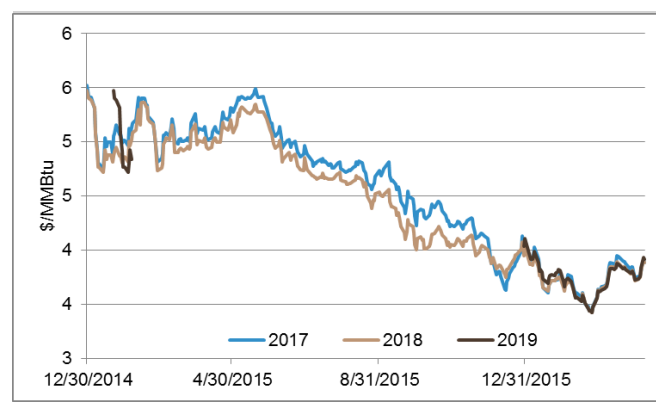
We believe new build plants in the region will continue to rely upon cheap- and declining delivered natural gas prices to the region to drive the equity returns on new investments in plant. The question remains whether sparks will improve at all given the vast majority of dispatch remains gas-driven (we believe yes still); however, the risk to the expanding spark story is the timeline for new renewable resources, pushing down LMPs. We see high regional RPS standards as fundamentally requiring high capacity to offset weaker regional energy margins. We also note that the new build costs and brownfield economics appear quite competitive – with Invenergy touting ~\$900/kW in some of its disclosures (a near record low for a CCGT in ISO-NE).

**Figure 24: Mass Hub ATC Pricing (\$/MWh)**



Source: Platts

**Figure 25: Algonquin Gas (\$/MMBtu)**

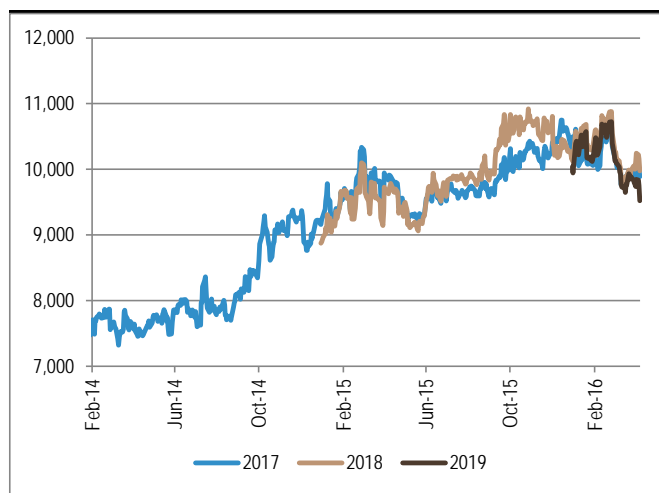


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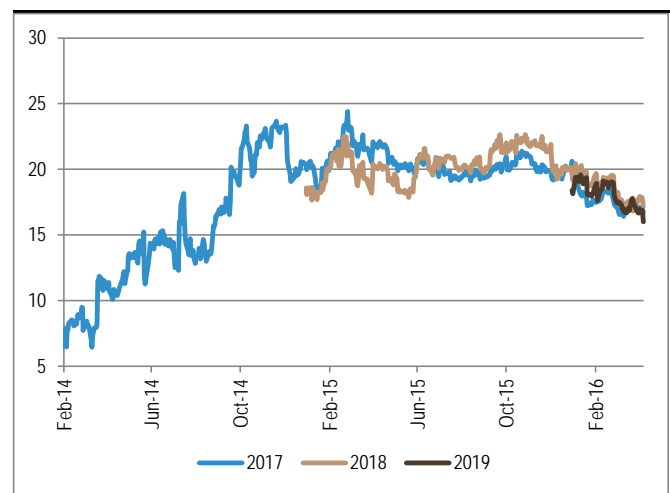
### Transmission imports – new lines are the wild card for future

The ISO has largely maxed out existing import capability from New York in each of its auction (with the exception of the Crosstown Cable, where Long Island is probably less likely to export to NE given historically NE has exported to them) – thus there weren't major changes to this times auction results on this front. The real wild card here are potential new transmission lines to import more resources into New England, and if one of those gets built, certainly that will change things a lot in terms of capacity imports. We note that there are indeed a number of different proposals for transmission capacity into the region through various RFPs; which could potentially be deemed capacity resources in subsequent periods. ISO NE confirmed on the call that there are rules in place that would allow a new transmission project to come in and qualify its capacity if it met certain criteria – but there are no cases yet qualified.

**Figure 26: Mass Hub Heat Rates (btu/KWh)**



**Figure 27: Mass Hub Spark Spreads @ 7.2**



*For further background we include links to recent reports below:*

[3/30/16: Dousing the New England Grid](#)

[2/18/16: What's New in New England? Learnings on the ...](#)

[2/12/16: Read All About It: Why The New England Print ...](#)

[2/11/16: Pouring Cold Water on New England Power](#)

[2/8/216: Adding to New England Import Prospects](#)

[UBS: Pouring Cold Water on New England Power](#)

[How Green Can New England Get?](#)

[Picking a Price for the New England Auction](#)

[New England Setting Pipes & Wires in Motion](#)

[ES: Sourcing Solutions for New England](#)

[Reaching the Summit in New England](#)

**Please see below for the auction results:**

[ISO-NE Forward Capacity Market 10 Results Report](#)

[ISO-NE State of the Grid 2016 January 2016 Presentation](#)

## New York: Summer Heat Melts Big Apple Capacity

### NYISO posted its latest summer strip price for 2016, materially lower for NYC

As anticipated, Summer 2016 capacity prices declined substantially in New York Independent System Operators (NYISO) NYC Zone-J to \$10.99/kW-mo from \$15.50/kW-mo, which we attribute primarily to the latest parameters with showed a substantial reduction of 'in-city' requirements. As for the wider regions, these continued to clear at relatively comparable levels. We see the results as supportive of upstate generators (DYN & TLN) while a more cautious datapoint on the fickle nature of highly-sensitive NYC capacity prices (principally NRG).

### What does the future bode? Follow upstate New York for clues

We see 2017 as a key year of potential upside for the Rest of State (RoS) market as there remains a clear potential capacity retirements (specifically nuclear). Clarity on asset decisions should grow this summer around the potential success of the nascent ['Zero Emission Credit' \(ZEC\) program in the state](#) and NY's ability to cut a deal to keep the 850MW FitzPatrick station open with a contract to support its cash flows. We see a general upward bias on capacity price trends downstate, albeit with a soft cap at the \$5.50-7.00/kW-mo level cap driven by arbitrage across capacity exports with New England

### Expect more transmission interconnection efforts for downstate NY

We emphasize efforts to bring more capacity downstate will continue as entities such as Avangrid (AGR) and Con Edison (ED) continue to pursue large transmission projects to reduce congestion into both the Lower Hudson Valley (LHV) and NYC zones. We look for a larger 130-200 mile DC interconnection project (Connect New York) in the coming month as particularly intriguing to put yet further prospective pressure. We expect the capacity spread between upstate and downstate to continue its decline structurally as bottlenecks are resolved, with the LHV zone eventually being eliminated entirely due to both new asset in-service as well as improved transmission. The offset appears to be the potential for LHV exports into New England potentially should prices support this trend. The latest AGR project would be among the first major recent transmission projects put forth by a utility under the NYISO's project solicitation efforts – and an outcome of the long-delayed Energy Highway initiative. The project would similarly enable the state to more readily accommodate any eventual retirement of Indian Point. Expect details and progress on new project timelines in 2016 (responses are due April 28<sup>th</sup>)

**Figure 28: UBS Capacity Price Forecast: Largely Inline**

	2016 UBSe	2016 Actual	2015 Actual	YoY change
<b>NYC Forecast</b>				
Summer ICAP (\$/kW-month)	10.00	10.99	15.50	-29.1%
<b>NY - Rest of State (RoS)</b>				
Summer ICAP (\$/kW-month)	4.25	3.62	3.50	3.4%
<b>Lower Hudson Valley Estimate</b>				
Summer ICAP (\$/kW-month)	8.07	8.25	8.50	-2.9%

Source: UBSe and NYISO

## What's the longer-term forecast?

We continue to express a more depressed outlook for the downstate regions in NYC and Lower Hudson Valley (LHV) as supply parameters and new capacity provide a lid on prices. We emphasize current prices limit the ability for mitigated assets such as the NJ-NY Hudson Transmission Partners (HTP) project from continuing to clear.

## What are the big questions in New York?

- **Nuclear policy to the rescue?:** Will the state succeed in putting in place a wider 'Zero Emission Credit' Market (ZEC) to keep in place existing capacity? Given the meaningful de-carbonization ambitions for the state and Governor, we see this as a still quite credible angle. Based upon legislative developments in New York we believe a deal to support ETR's FitzPatrick is still in the realm of possibility, potentially in a deal involving its other nuclear assets in the state - this represents potential upside for ETR shares. Further, we emphasize shares of EXC remain intriguing around prospects for a deal to keep not just its Ginna plant afloat but now *also* its Nine Mile facility as well (a larger dual unit nuclear plant). We look for updates on this throughout the Spring into the ~June timeframe around which a framework is contemplated.
- **Renewable policies scaling: How quickly will this translate?** With New York having recently enacted its own 50% RPS as part of a recent trend, we see this as ensuring continued structural pressures on power prices. As such, we see the state as poised to keep support on capacity prices amidst a need to remunerate generators whose primary revenue sources had previously been oriented energy margins. We look for New York to begin to scale its renewable procurement efforts as a function of wider execution on its RPS goals embedded within the Reforming the Energy Vision (REV) ambitions. Specifically we expect the state to ultimately turn to some longer-dated PPA procurement mechanism to enable the most cost effective procurement of such projects.
- **Will New England keep NY capacity trying to export?** We see a continued argument that elevated New England capacity prices will put structural pressure on New York to continue to push out capacity MWhs into this adjacent market. *The question remains at what price?*

ETR continues to state that it will close its FitzPatrick plant.

How to meet the future New York renewable goals? Imports.

Amidst this focus on transmission, it appears New York state is likely to turn to imports from adjacent regions to source its renewable requirements.

While Blackstone has proposed its long-standing TDI project, we see a wider interest in developing such capacity to expand hydro imports. We think the 50% RPS will be established to include external hydro as qualifying.

## Where are power prices trending? Some Recovery

We include the latest Zone A (West), Zone G (Lower Hudson Valley) and Zone J (New York City) ATC prices to illustrate power price trends.

Figure 29: NY-Zone A ATC Power (\$/MWh)



Source: Platts

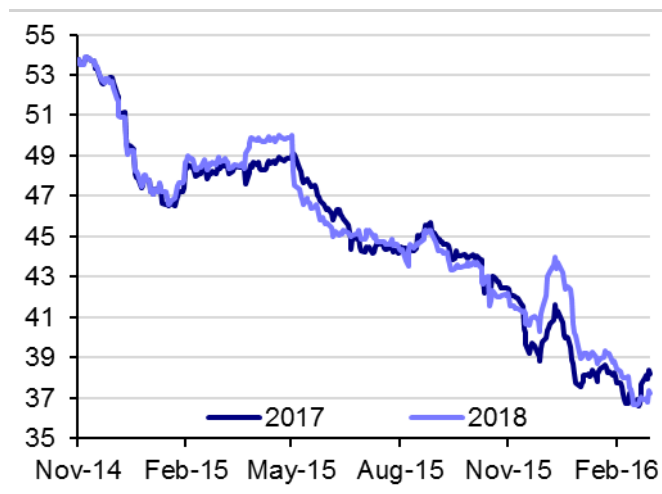
Figure 30: NY-Zone G ATC Power (\$/MWh)



Source: Platts

While all three regions have faced downward pressure, Zone J has fallen the sharpest (~30% over the period) given more structural pressures.

**Figure 31: NY-Zone J ATC power prices (\$/MWh)**

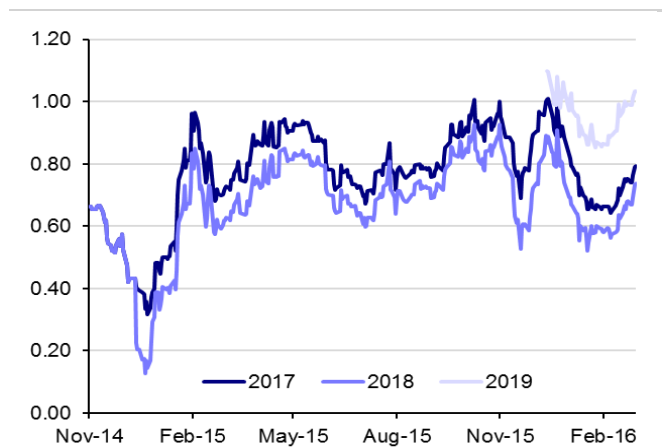


Source: Platts

### Finally what about gas basis? Some improvements.

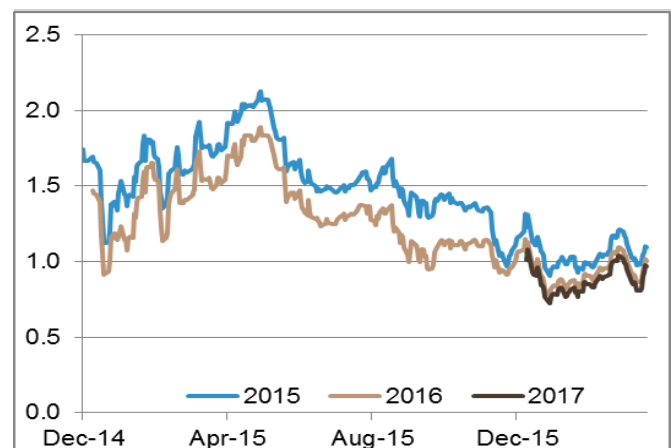
We include the Transco Zn 6 trends as well as Mass Hub price trends below. While muted vs. the highs, both have seemingly recovered in recent weeks as it has become clear the Constitution pipeline project will be delayed service into 2017.

**Figure 32: Transco Zone 6 Gas Basis W/O Henry Hub (\$/MMBtu)**



Source: Platts

**Figure 33: Gas Basis W/O Henry Hub – Algonquin (\$/MMBtu)**

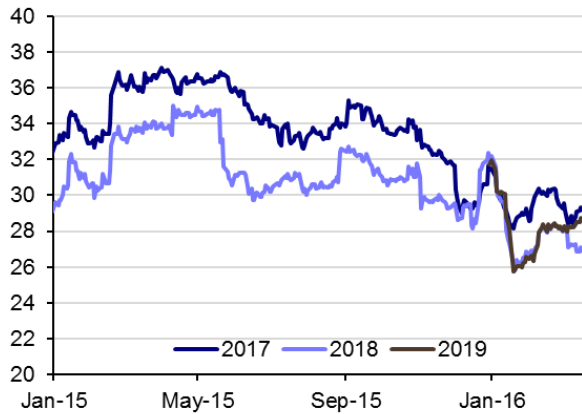


Source: Platts

### And finally, what about sparks on gas assets?

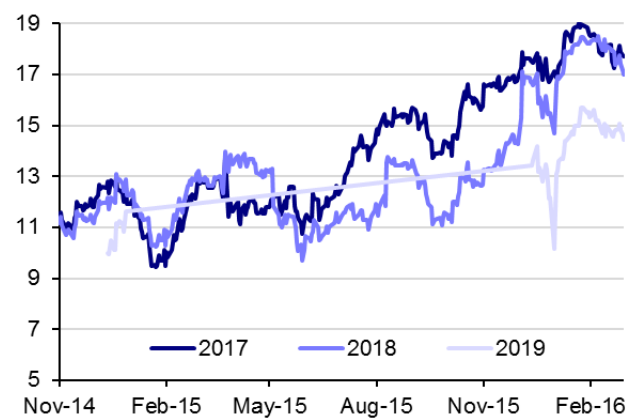
We also include the spark spread trends in each of these markets. We include principally sparks on the Zone G sparks, where most of the contemplated projects are contemplated at present.

**Figure 34: Spark Spread: Zone G @ 7.2 heat rate (Dom South Gas) (\$/MWh)**



Source: Platts

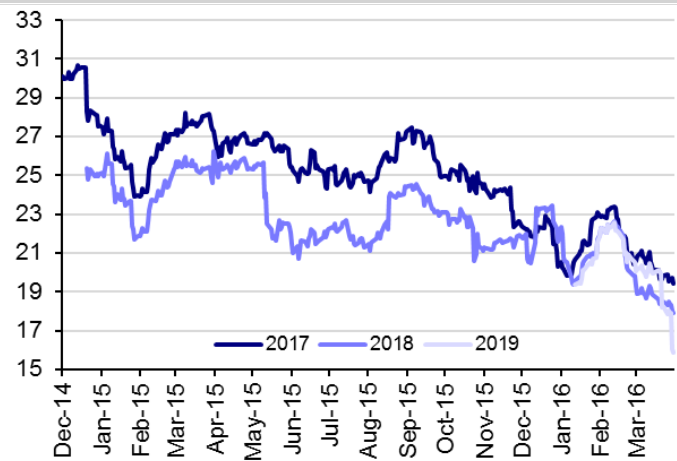
**Figure 35: Spark Spread: Zone A @ 7.2 heat rate (Transco Zone 6 Gas) (\$/MWh)**



Source: Platts

We also include NYC sparks in this region, also reaching recent lows.

**Figure 36: Spark Spread: Zone J @ 7.2 heat rate (Transco Zone 6 Gas) (\$/MWh)**



Source: Platts

*For further background we include links to recent reports below:*

[4/5/16: Summer Heat Melts Big Apple Capacity Pricing](#)

[2/3/16: Nuclear Lifeline in \[Upstate\] NY](#)

[1/22/16: Taking A Bite out of the Big Apple](#)

[11/3/15: 'Ya Gotta Believe' NY Prices Are Heading Higher](#)

## California: Arguing the Near-Term Case

### We see power prospects in California improving in the near-term

For once we can actually see a more constructive thesis on power emerging in California around the gas leak and prospects for higher gas prices more broadly, enabling among the few opportunities to be bullish on this market through the medium term. With investors more keen to take on gas exposure, we emphasize the California market would appear among the more levered markets to gas given the limited switching (with power prices quite correlated in a real-time basis to core power prices). Further, with clear potential for added volatility due to instability this would appear to add value to the intrinsic value of gas assets given their ability to monetize this volatility. With expectations having been quite low for years in California, the state could be turning a corner on pricing in 2016.

### Why are we more comfortable on prospects? Four key reasons

We see a litany of factors converging in the state to improve prospects: 1) We see the ongoing Aliso canyon as adding to SoCal gas basis, but also notably adding to upside risk in the event of weather events through the next 12-month period; further without the storage facilities' fate known, we see prospects for a structural shift upwards in regional gas basis and volatility; 2) We see prospects for meaningfully higher delivered gas rates for generators behind the PG&E gas LDC (as a result of the pending GT&S case) to push rates up significantly, including for DYN's Moss Landing CCGT; and 3) we emphasize the market remains exposed to gas prices with gas plants remaining 'marginal' in the region. 4) We see recent market kick-off in Mexico as enabling assets to begin to 'exit' California and export South, with both SRE and CPN exploring such options.

We see markets such as California as positioned to see a turnaround as substantially all thermal capacity is gas; we see the ongoing Aliso Canyon gas storage dynamic adding to regional gas basis and volatility alongside materially higher delivered gas rates from the pending PG&E GT&S case to generators behind the LDC. We emphasize our view is short to medium term in nature, with the longer-term outlook clearly pressured by the continued (and out of market) procurement build of renewables to meet the states' Renewable Portfolio Standard (RPS).

### Admittedly, longer-term prospects remain challenged from renewables

We admit longer-term prospects remain constrained as pricing continues to shift away from spark spreads towards capacity compensation. While CPUC reports indicate a stabilization in pricing around ~\$3/kw-mo on average for units receiving such payments (those not receiving it are not included in this figure), we project limited appreciation potential given the limited leverage from the three utilities. The question remains whether localized RA could see some improvement, particularly at year-end 2017 with the bulk of the once-through cooled units required to retire by this point (we believe others could retire before given the limited economics through end of life).

### What does this mean for stocks? Supportive to our CPN thesis

Bottom line, we continue to see CPN as our preferred play on Power. While its leverage remains exposed to the fluctuations of the high-yield energy credit markets, we see the stock as still among the more intriguing value propositions, particularly amidst its latest underperformance vs more gas-sensitive peers. We see Texas- and now California as among the more intriguing markets, the two core markets CPN- in contrast to Northeast markets, which appear poised to peak (and the core exposure for all other public IPPs)

### What about others? Looking at NRG and DYN's positioning too

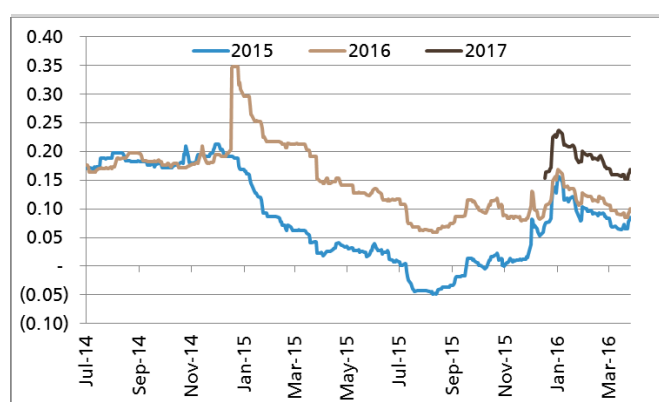
We flag much of NRG's capacity has limited energy market sensitivity and is largely contracted where value exists. As for DYN, much of the value for this generator remains tied to the ongoing GT&S case; a negative decision could largely remove most of the equity value for its single CCGT, Moss Landing 1&2. We continue to

look for a sale announcement as part of its previously announced divestment from the state; a deal could well include a sliding scale of value depending on how the case is resolved.

### Gas leak driving up SoCal Gas Basis

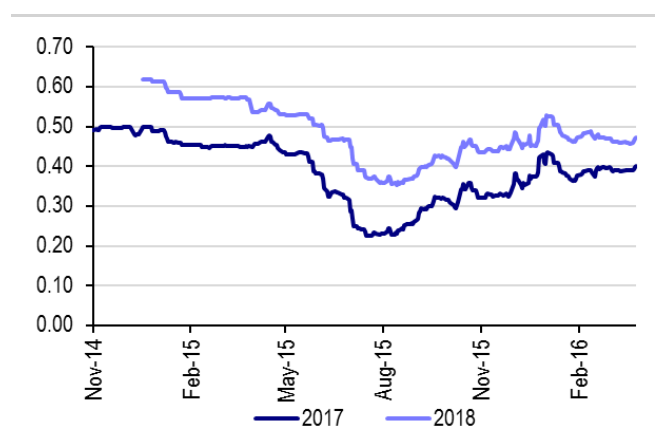
Although the leak that resulted from the blowout at the Aliso Canyon facility is plugged, Southern California Gas (SoCalGas – subsidiary of Sempra Energy), the operator of the facility, is prohibited “from injecting natural gas into the underground reservoir” until a safety inspection is completed, according to a report from the California Public Utilities Commission (CPUC). In addition to not being able to provide gas for the energy demands in the region, only one-fifth of the total capacity of the facility remains in the reservoir following the leak. We emphasize the lower supply could cause significant price spikes for generators, and ultimately ratepayers, as the company flows the costs through.

**Figure 37: SoCalGas Gas Basis (\$/MMBtu)**



Source: Platts

**Figure 38: PG&E City Gate Gas Basis (\$/MMBtu)**



Source: Platts

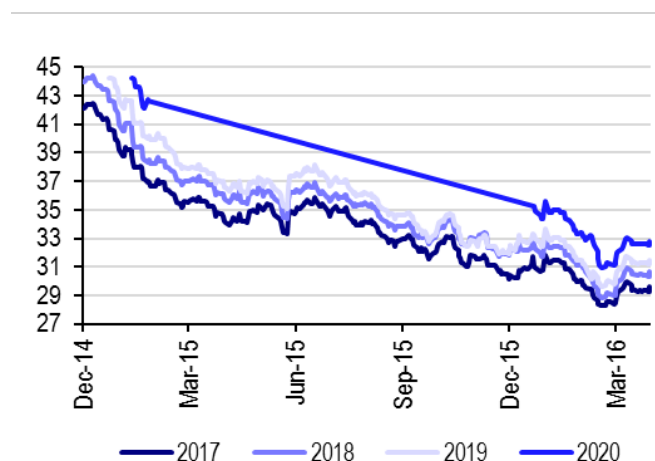
From this, we see power prices as having found a recent-floor.

**Figure 39: NP15 ATC Power Prices (\$/MWh)**



Source: Platts

**Figure 40: SP15 ATC Power Prices (\$/MWh)**

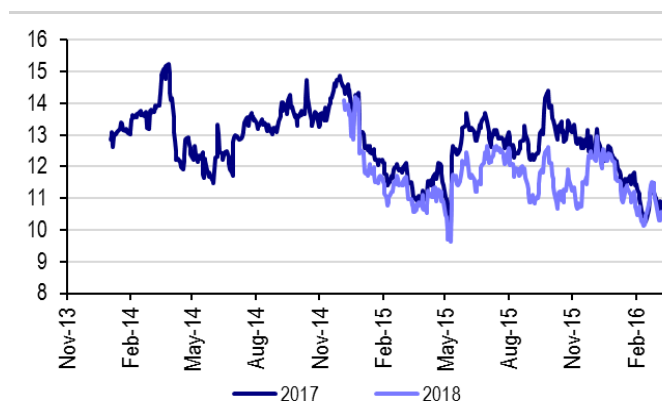


Source: Platts

**Finally, what does this mean for sparks?** We've seen sparks trend downwards in recent months still, albeit see potential for a recovery amidst a variety of factors becoming more firmly recognized. We emphasize that spark spreads in the state should remain quite correlated to improving gas price trends in the near-term,

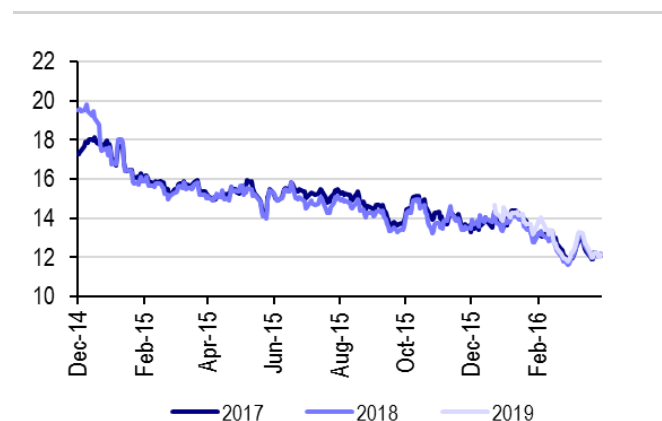
adding to the angle around prospects for improvement. Further, off these lower levels, the question

**Figure 41: NP15 Spark Spread (\$/MWh)**



Source: Platts

**Figure 42: SP15 Spark Spread (\$/MWh)**



Source: Platts

### How long could the storage facility be out?

Aliso Canyon is an integral part of the energy system in SoCal and the constraints put on the facility will have an adverse impact on the service area, especially during the summer and winter months. The report from the CPUC states, "Without any gas supply from Aliso Canyon, there are 14 days this coming summer during which gas curtailments could be high enough to cause electricity service interruptions to millions of utility customers." This statement remains more a comment on risk mitigation from CAISO rather than a likely outcome.

### PG&E's Gas Rate Case: Another Material Gas Inflator

Yet another driver of power price inflation in the near term is the pending GT&S case for PG&E. We understand the substantial focus on safety-related spending could add upwards to \$1/MMBtu under the pending case (from \$0.035/MMBtu today to ~\$1.35/MMBtu under the proposal). While a Proposed Decision (PD) from the CPUC remains pending, we're not surprised to see the delay given the magnitude of the pending rate increase on generators – and other customers behind the citygate. We emphasize with their bids reflecting these additional costs, there could yet be a step-change in California bid power costs later this year. We remind investors that the increase was so substantial that DYN pulled its asset sale last year of its West coast portfolio pending the uncertainty; the hike would effectively limit any dispatch. The argument between DYN and PG&E relates to what is the 'profit maximizing' decision for PG&E with the increase effectively meaning the project will no longer consumer gas.

We note Calpine is also located in Northern California, largely with non-coastal, interior plants, not exposed to shifts in the pending GT&S case. In fact, the only plant that was materially exposed was Sutter, which was recently mothballed.

### California's drought remains the primary driver of spark spreads

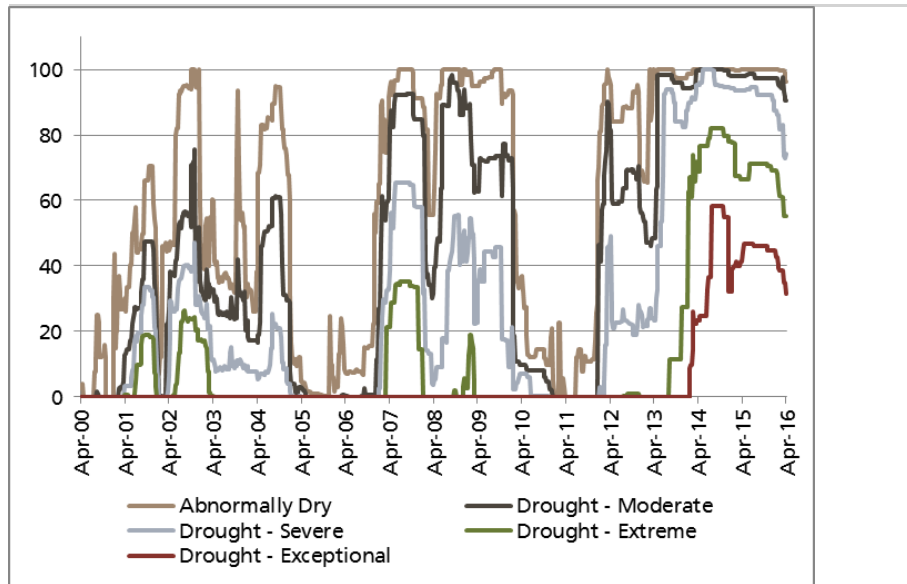
We note one mitigating factor that may have an impact on power prices in the region – drought. **California is facing their fifth year of drought; however, the conditions are improving as evidenced by the below Drought Monitor.** Given the high hydro-portion of their mix, we see a lower demand for natural gas stemming following

**We see significant risk of increase to dispatch costs**

**Easing drought conditions remain the primary headwind to power**

increased rain fall and moisture. This one factor may offset some of the potential gains that would be recognized as a result of the pressures on gas supply. We see this as the primary factor driving down basis in recent weeks after the initial pop from the Aliso Canyon disturbance.

**Figure 43: Drought Monitor – Easing Conditions offer offset to the otherwise improving outlook**



Source: United States Drought Monitor

### Risk of Mexican exports from California also of close focus

Following the inaugural capacity auction in recent weeks in Mexico, we see risk for capacity to attempt to de-link from the CAISO to join the Mexican market. We see this as a clear potential for Semptra's TDM facility (albeit potentially under a new owner); this 625 MW facility would be the *first* to leave, but with others potentially following. For instance, Calpine is evaluating exporting capacity from its Otay Mesa plant as well among other options for its large installed base in the state. The plant would otherwise be sold to SDG&E at the conclusion of its existing contract. Further, the question remains whether other assets in Calpine's California fleet could yet take advantage of export rights. We emphasize we have already seen this manifest itself in ERCOT.

*For further background we include links to recent reports below:*

[3/31/2016: Can Power Keep Up With Gas?](#)

[2/12/2016: Gas Storage: Framing Aliso Canyon in the Context of Safety](#)

[1/7/2016: West Waiting for a Better 2H16](#)

## Other Commodity Price Trends

*Below we include commentary from our oil & gas colleagues from their April 19<sup>th</sup> note [\[please click here for the full report\]](#).*

### Recently lowered our near-term US natural gas price forecasts...

We lowered our 2Q16 & 3Q16 natural gas price forecasts (\$/MMBtu) to \$2.00 & \$2.25 (from \$2.40 & \$2.50 prior), respectively, reflecting weaker than expected spot prices & the need for continued low near-term gas prices to reduce the uncomfortably high inventory surplus heading into the winter of 2016-17. Importantly, we estimate the warmer than normal winter resulted in ~800 Bcf of lost demand which left storage exiting the withdrawal season at nearly ~2.5 Tcf (~900 Bcf above normal). And assuming normal weather, we estimate the injection season ends with storage at 3.9 Tcf (100 Bcf above normal), but this requires prices staying low this spring/summer to continue encouraging strong coal-to-gas fuel switching (up ~4.1 Bcfd YoY in 2015 and another >2 Bcfd YTD) to prevent a massive storage surplus heading into next winter.

### ...but raised our 2017 natural gas price forecast on a tighter market next year

We raised our 2017 natural gas price forecast (\$/MMBtu) from \$2.75 to \$3.00 as we now see a tighter market next year driven by 3 factors: 1) further reduction in drilling activity (US gas rig count down from ~340 at YE14 to 89 currently) which we expect will help drive natgas volumes down ~1% YoY next year (vs. growth prior); 2) significant reduction in ethane rejection in 2017 (>1 Bcfd of YoY decline in natgas volumes); & 3) several notable pipeline delays in the northeast constraining the region's supply growth (e.g. Constitution, Atlantic Sunrise, PennEast, & ET Rover). We've left our 2018 & normalized price forecasts unchanged at \$3.00 & \$3.25, respectively.

We show below latest UBS forecast for US nat gas:

**Figure 44: Revised UBS Natural Gas Price Forecasts (2016-18E and Normalized)**

	2014A	2015A	1Q16A	2Q16E	3Q16E	4Q16E	2016E	2017E	2018E	2019E	2020E	Normalized
<b>Natural Gas NYMEX (\$/MMBtu)</b>	<b>\$4.45</b>	<b>\$2.67</b>	<b>\$2.09</b>	<b>\$2.00</b>	<b>\$2.25</b>	<b>\$2.60</b>	<b>\$2.25</b>	<b>\$3.00</b>	<b>\$3.00</b>	<b>\$3.25</b>	<b>\$3.25</b>	<b>\$3.25</b>
<i>Previous Estimate</i>				<i>\$2.40</i>	<i>\$2.50</i>	<i>\$2.60</i>	<i>\$2.45</i>	<i>\$2.75</i>	<i>\$3.00</i>	<i>\$3.25</i>	<i>\$3.25</i>	<i>\$3.25</i>
<b>First Call Consensus</b>				<b>\$2.23</b>	<b>\$2.50</b>	<b>\$2.72</b>	<b>\$2.45</b>	<b>\$2.90</b>	<b>\$3.25</b>	<b>\$3.38</b>	NA	NA
<b>Futures Strip Price</b>				<b>\$2.00</b>	<b>\$2.23</b>	<b>\$2.55</b>	<b>\$2.22</b>	<b>\$2.82</b>	<b>\$2.89</b>	<b>\$2.96</b>	<b>\$3.07</b>	NA
<i>UBS vs Consensus</i>				-10%	-10%	-4%	-8%	3%	-8%	-4%	NA	NA
<i>UBS vs Strip prices</i>				0%	1%	2%	1%	6%	4%	10%	6%	NA

Source: Source: UBS estimates, FactSet, and Bloomberg

## Dominion-South and TETCO

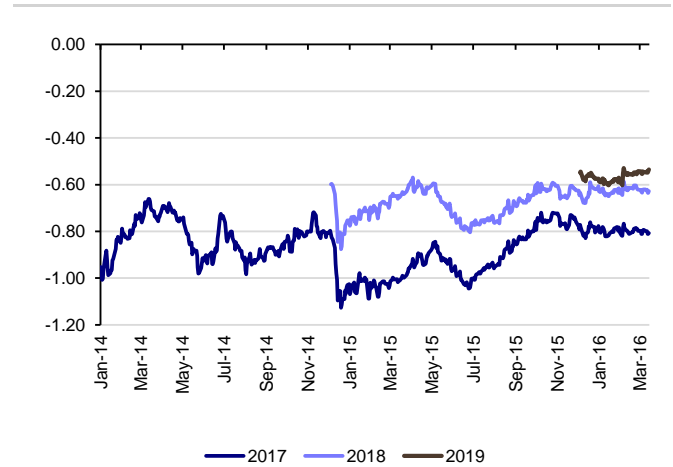
Gas basis little changed for either TETCO or Dominion South in recent months.

**Figure 45: TETCO w/o Henry (\$/mmbtu)**



Source: Platts

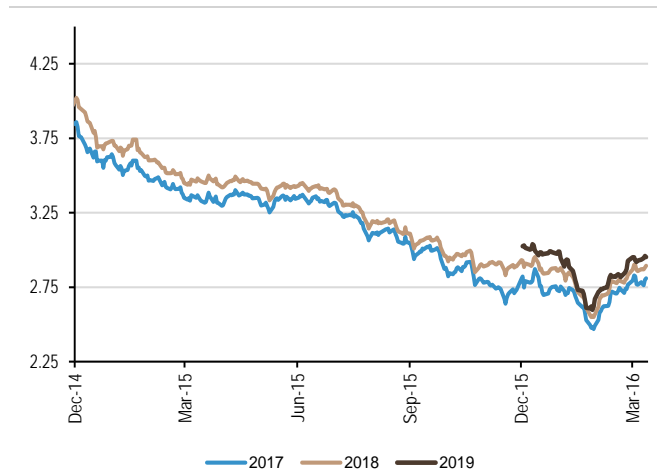
**Figure 46: Dom South w/o Henry (\$/mmbtu)**



Source: Platts

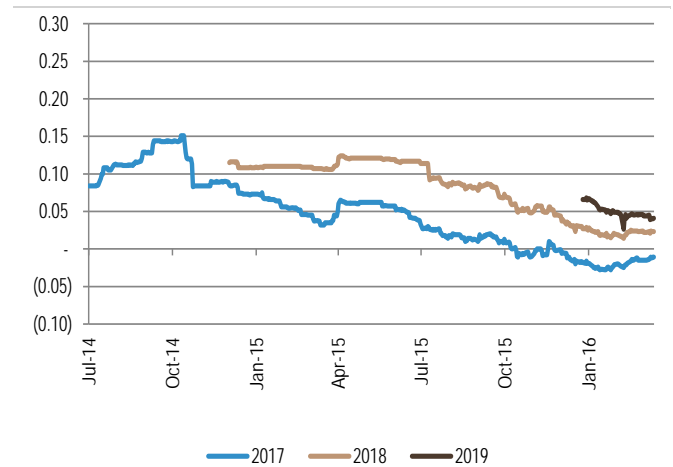
Henry Hub has stabilized in recent weeks while the Houston ship channel basis continues to decline.

**Figure 47: Henry Hub (\$/mmbtu)**



Source: Factset

**Figure 48: Houston Ship Channel w/o Henry (\$/mmbtu)**



Source: Platts

## Where did spot prices trend?

We include the spot prices across several key markets for 1Q which shows sharp declines across the board and multi-period lows for many markets.

Figure 49: Peak Spot Power Prices

Power Price \$/MWh								
Quarter End	PJM West	PJM East	CAISO	ERCOT	MISO Indiana	MISO Illinois	NEISO	NYISO
3/31/2016	29.6	31.4	23.9	19.0	32.0	25.9	29.4	29.3
12/31/2015	30.6	28.5	31.5	21.1	31.4	25.6	30.5	25.0
9/30/2015	38.1	40.5	40.1	33.0	37.3	32.0	38.5	36.6
6/30/2015	37.7	37.1	25.7	27.2	38.2	29.7	29.0	32.8
3/31/2015	57.3	67.4	32.3	26.5	37.0	31.9	87.0	78.3
12/31/2014	39.9	48.3	43.0	33.6	44.6	35.6	46.1	41.4
9/30/2014	41.6	45.4	49.7	37.1	58.5	36.4	40.7	40.1
6/30/2014	48.3	51.5	45.6	41.0	35.2	46.1	42.9	44.0
3/31/2014	104.5	123.1	53.4	53.3	38.0	50.8	159.3	138.9
<b>3/31/2016 vs 3/31/2015</b>	<b>-48%</b>	<b>-53%</b>	<b>-26%</b>	<b>-28%</b>	<b>-14%</b>	<b>-19%</b>	<b>-66%</b>	<b>-63%</b>

Source: Bloomberg

## With cheap gas, sparks didn't do well though.. yet another terrible quarter

PJM West sparks were resilient but the same cannot be said about PJM East. New England was a rare bright spot but came off of a very low base in 1Q15. This is amongst the most sobering commodity trend of late; the question remains just how much of this is attributable to the mild weather vs. lower gas prices.

Figure 50: Qtr Avg Spark Spreads @ 7.2 HR

7.2 HR Spark Spread \$/MWh						
Quarter End	PJM West	PJM East	CAISO	ERCOT	NEISO	NYISO
3/31/2016	16.7	18.5	8.0	5.2	11.9	10.3
12/31/2015	21.5	19.4	12.0	6.0	8.4	11.7
9/30/2015	28.5	31.0	17.5	13.4	21.8	21.1
6/30/2015	26.4	25.8	3.7	7.8	13.1	15.6
3/31/2015	16.5	26.5	10.3	6.7	2.5	14.9
12/31/2014	20.6	29.0	12.8	7.3	8.3	19.3
9/30/2014	24.3	28.1	16.9	8.6	19.0	22.6
6/30/2014	22.4	25.5	9.2	8.2	12.5	18.0
3/31/2014	21.2	39.8	13.1	16.8	13.0	24.1
<b>3/31/2016 vs 3/31/2015</b>	<b>2%</b>	<b>-30%</b>	<b>-23%</b>	<b>-22%</b>	<b>376%</b>	<b>-31%</b>

Source: Bloomberg

## Forward ATC Heat Rates

We include the latest forward heat rate outlook by market.

**Figure 51: Forward ATC Heat Rates (MWh/MMBtu) by Power Market**

	2016	2017	2018	2019
NP15 / PG&E	11.65	10.60	10.44	10.45
YoY % Change		-9.1%	-1.5%	0.2%
ERCOT-S/Houston Shipping	12.44 	12.45 	12.49 	12.45
YoY % Change		0.0%	0.4%	-0.3%
NYISO Zn G / Transco Zn 6	15.16 	12.09 	11.45 	11.38
YoY % Change		-20.3%	-5.3%	-0.6%
Southern / Transco Zn 4	11.44 	10.84 	10.67 	10.50
YoY % Change		-5.2%	-1.6%	-1.6%
Mass Hub / Algonquin	11.10 	11.47 	11.70 	11.00
YoY % Change		3.3%	2.1%	-6.0%
Entergy / Henry Hub			12.64 	12.41
YoY % Change				-1.9%
NI Hub / Chicago Citygate	13.46	11.95	11.67 	10.56
YoY % Change		-11.2%	-2.4%	-9.5%
PJM West / TETCO M3	19.44 	15.46 	13.95 	13.52
YoY % Change		-20.5%	-9.7%	-3.1%
AD Hub / MichCon	14.46 	12.60 	12.19 	11.08
YoY % Change		-12.9%	-3.2%	-9.1%
ERCOT-Houston/Houston Ship	12.79 	12.79 	12.56 	12.63
YoY % Change		0.0%	-1.8%	0.6%
ERCOT-West/Houston Ship	11.88	11.98	11.91 	11.85
YoY % Change		0.8%	-0.6%	-0.5%
ERCOT-North/Houston Ship	12.06 	12.16 	11.99 	12.07
YoY % Change		0.8%	-1.4%	0.6%
CIN-Hub/ Chicago Citygate	13.37 	11.86 	11.88 	11.56
YoY % Change		-11.2%	0.1%	-2.7%
<b>Average</b>		<b>-7.1%</b>	<b>-2.1%</b>	<b>-2.6%</b>
<b>4Q15 Average</b>		<b>-8.6%</b>	<b>-2.4%</b>	<b>1.5%</b>
<b>3Q15 Average</b>		<b>-3.7%</b>	<b>-5.5%</b>	<b>1.5%</b>
<b>2Q15 Average</b>		<b>-2.6%</b>	<b>-2.4%</b>	<b>1.3%</b>
<b>1Q15 Average</b>		<b>-3.5%</b>	<b>-2.7%</b>	<b>1.3%</b>
<b>4Q14 Average</b>	<b>-4.2%</b>	<b>-4.2%</b>	<b>-2.5%</b>	

Source: Platts, UBS

## Regional Heat Rate Trends

The picture for regional heat rates is mixed with expansion in most parts of the country with New York and the Midwest as notable exceptions.

**Figure 52: ATC Heat Rates – Change YoY for Forward 2017**

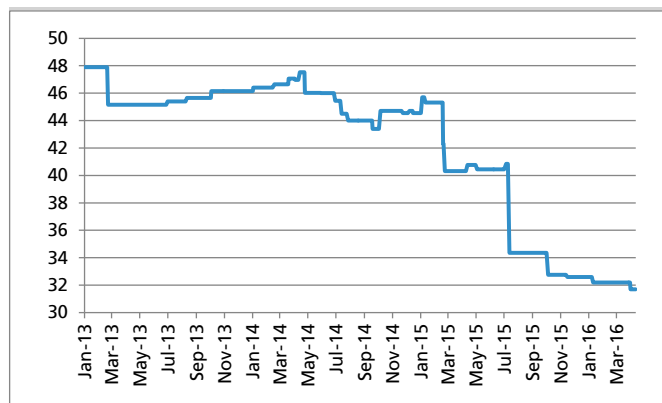
ATC Heat Rates 2017					
	ERCOT-North	ERCOT-Houston	ERCOT-West	ERCOT-S	Southern
Apr-16	9,796	10,642	9,653	10,017	9,611
Apr-15	9,344	9,910	9,040	9,639	9,528
YoY % Change	5%	7%	7%	4%	1%
	NY-ZnG	NY-ZnJ	NY-ZnA	MassHub	
Apr-16	10,228	10,728	11,283	9,825	
Apr-15	11,278	11,791	10,566	9,836	
YoY % Change	-9%	-9%	7%	0%	
	PaloVerde	SP15	NP15	MidC	
Apr-16	12,039	10,977	9,572	8,009	
Apr-15	10,919	10,436	9,168	8,428	
YoY % Change	10%	5%	4%	-5%	
	Indy Hub	NI Hub	ADHub	PJM-W	
Apr-16	10,093	9,909	11,013	13,011	
Apr-15	10,551	9,605	10,736	11,762	
YoY % Change	-4%	3%	3%	11%	

Source: Platts, Bloomberg

## Coal Price Trends

Coal prices remain weak, and we expect continued pressure as domestic power demand gets impacted a) on a near term basis because of gas price-induced switching; but more fundamentally long term as coal plants are retired due to environmental regulation and substantial MWs are replaced by gas and renewables instead. We show below price evolution for coal at Illinois basin and PRB:

**Figure 53: Illinois basin coal prices**



Source: Bloomberg

**Figure 54: PRB coal prices**



Source: Factset

## Capacity Projections by Region

We reflect the summary of our latest historical and projected capacity prices below including the latest from New England, New York, MISO and PJM.

**Figure 55: Capacity Market Projections by Region**

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
<b><u>PJM (\$MW-day)</u></b>												
RTO	111.9	102.0	174.3	110.0	16.5	27.7	126.0	136.0	134.0	151.5	150.0	140.0
EMAAC	148.8	191.3	174.3	110.0	139.7	245.0	136.5	167.5	134.0	151.5	210.6	225.4
SWMMAAC	210.1	237.3	174.3	110.0	133.4	226.2	136.5	167.5	134.0	151.5	150.0	140.0
MAAC				110.0	133.4	226.2	136.5	167.5	134.0	151.5	150.0	140.0
DPL-S			186.1	110.0	222.3	245.0	136.5	167.5	134.0	151.5	150.0	225.4
PS-N					185.0	245.0	225.0	167.5	134.0	151.5	210.6	225.4
PSEG					139.7	245.0	136.5	167.5	134.0	151.5	210.6	225.4
PEPCO						247.1	136.5	167.5	134.0	151.5	150.0	140.0
ATSI								357.0	134.0	151.5	150.0	140.0
ComEd						27.7	126.0	136.0	134.0	151.5	215.0	215.0
PPL						226.2	136.5	167.5	134.0	151.5	164.8	140.0
<b><u>ISO-NE</u></b>												
Annualized (\$/kW-Month)	3.65	3.95	4.19	3.59	2.78	2.53	2.72	3.02	2.99	5.30	8.50	8.08
Clearing Price/Pro-Rated	3.75	4.10	4.25	3.12	2.54	2.52	2.86	3.13	2.88	7.03	9.55	7.03
<b><u>NYISO - Zn J</u></b>												
Summer ICAP (\$/kW-month)	6.50	6.75	12.90	13.54	11.70	14.80	16.24	15.50	10.00	10.00	11.00	11.00
Winter ICAP (\$/kW-month)	1.91	2.79	4.65	4.60	2.70	4.50	7.54	8.45	6.67	6.67	6.67	6.67
NYISO Zn J (\$/kW-month)	4.35	5.08	8.77	8.75	7.50	10.16	12.04	11.68	8.34	8.34	8.84	8.84
NYISO Zn J (\$/kW-yr)	52.22	60.96	105.20	105.04	90.00	121.88	144.50	140.14	100.02	100.02	106.02	106.02
<b><u>NYISO - RoS</u></b>												
Summer ICAP (\$/kW-month)	2.67	3.01	2.47	0.55	1.25	5.80	5.15	3.50	4.25	7.00	5.00	5.00
Winter ICAP (\$/kW-month)	1.91	1.77	1.75	0.39	0.15	0.82	2.58	2.90	2.35	4.50	4.50	4.50
NYISO - RoS (\$/kW-month)	2.27	2.39	1.88	0.43	0.81	2.80	3.92	3.11	3.66	5.75	4.75	4.75
NYISO - RoS (\$/kW-yr)	27.20	28.64	22.60	5.16	9.74	33.64	47.02	37.29	43.88	69.00	57.00	57.00
<b><u>NYISO - LHV</u></b>												
Downside case - assumption	2.67	3.01	2.47	0.55	1.25	4.20	5.15	3.50	3.62	7.00	5.00	5.00
Winter ICAP (\$/kW-month)	1.91	1.77	1.75	0.39	0.15	0.82	2.58	2.90	1.25	2.35	4.50	4.50
NYISO - RoS (\$/kW-month)	2.27	2.39	1.88	0.43	0.81	2.80	3.92	2.93	2.62	5.03	4.75	4.00
NYISO - RoS (\$/kW-yr)	27.2	28.64	22.6	5.16	9.74	33.64	47.02	35.10	31.41	60.38	57.00	48.00
<b><u>MISO Capacity Values:</u></b>												
IPA Auctions (\$/kW-yr)	12.41	8.46	0.67	0.18	3.70	0.38	6.11					
Calendarized (\$/kW-yr)		10.44	4.57	0.43	1.94	2.04	3.25					
MISO RA Auction (\$/MW-day)						1.05	16.75	150.00	72.00	50.00	50.00	50.00
Calendarized (\$/KW-yr)							3.73	34.48	38.14	21.60	18.25	

Source: PJM and UBSe (Note: actual and forecasts prices for PJM represent base capacity auction prices)

# Power Market Preferences

We continue to prefer ERCOT seeing that market as being closest to the bottom with more retirements coming later in the decade due to poor economics and impending environmental rules. We have switched CAISO and MISO at the bottom with California improving in our view based upon the latest issues of gas storage that should be supportive to power prices. Following the ~50% decline in capacity prices and no firm timeline for favorable reforms, we are lowering MISO to be our least preferred market. While there is a limited outlook for recovery today this could reverse if Dynegy and Exelon close assets like they have discussed as a possibility and/or we see further exports into PJM.

## More renewables? The sobering side of Power.

We see expanded efforts to procure renewables in New York and New England as driving our reduced expectations. The question remains timeline, seeing NIMBY concerns and protracted development of corresponding transmission limiting this to a medium-to-longer term impact (albeit a potentially large one at that). Transmission from Canada of Hydro remains alive and well – and a likely reality for IPPs in both regions.


**What has changed in our power market preferences?**

**Up on CAISO and PJM**

**Less on ISO-NE and NYISO on growing renewable concerns**

**ERCOT's the only *rea*/market we have confidence in medium-term improvement**

**Figure 56: Power Market Preferences**

UBS Preferred Power Market List - Rank Order				
Preference	New Rank	Old Rank	Market	Reasoning
<b>Most Preferred</b> 	1	1	ERCOT	New entry slowing, with regulatory reforms back on the table, its time for asset retirements, finally.
	2	2	ISO-NE	Latest capacity retirements and reforms should provide some resiliency to pricing
	3	4	PJM	Reforms largely reflected-- support on capacity offset by continued new gas entry
	4	3	NYISO	We see new gas and new supply as driving down capacity prices
	5	6	CAISO	Increasing gas prices from Aliso Canyon leak and GT&S rate case should help in near-term
<b>Least Preferred</b>	6	5	MISO	Combo of low-cost wind and challenging market construct. Potential DYN/EXC retirements will be key

Source: USB Estimates

# Ameren Corp.

Shares are flat versus the broader group in 2016 but have oscillated between +/- 200bp relative performance as investors continue to debate the likelihood of legislation passing in Missouri. The Missouri legislation has made good progress (passed the House 142-4) but the Senate remains key. Investors have begun embedding a low level of uplift in Missouri so we see risk to estimates if the legislation is not approved but disproportionately more upside if approved. Per Bloomberg Ameren among other parties is interested in potentially acquiring neighbour utility Westar (WR); acquiring utilities have tended to underperform on a deal announcements which has caused some investors to be hesitant on AEE.

We forecast AEE reporting adjusted 1Q16 EPS of **\$0.34**, well below consensus (\$0.44) which expects a flat quarter YoY despite significant headwinds for the quarter. The most significant negative is weather where 1Q15 was above-average and 1Q16 was below average. Other negative items include the absence of the 1Q15 ICC power recovery benefit (-\$0.04) and the impact of Noranda's lost load (~\$-0.02). Higher ratebase for transmission/gas and lean efforts in Missouri are offsets but we do not estimate they are enough to drive flat performance compared with last year.

AEE expects to book some of the expected ~\$19Mn performance incentive later in 2016 (not in 1Q16) to help offset the effects of the program in 2016. Management also noted that the current EE efforts will likely lead to flattish sales in 2016 and 2017.

Between unfavorable weather comparisons and negative one-time impacts we see quarterly consensus expectations for ~flat EPS as overly optimistic

Figure 57: AEE 1Q16E Earnings Walk

Ameren Corp 1Q16 Earnings Walk	EPS
<b>1Q15A Adjusted EPS</b>	<b>\$0.45</b> Notes
Weather vs Normal in 1Q15	(0.05) Return to Normal Weather; ~5-10% above normal HDD
Weather vs Normal in 1Q16	(0.06) Degree Days in Current Year; ~13-15% below normal HDD
MO Electric: New Rates	0.01 \$122Mn Increase Effective May 30, 2015
MO Electric: Energy Efficiency Impact	(0.01) \$19Mn of performance incentive (2H16E); flattish sales in 2016
IL Electric: Higher Rates (Formulaic)	0.02 \$106Mn Increase Effective January 2016
IL Gas: Higher Rates	0.01 \$45Mn Increase Effective Late December 2015
ATX and IL Transmission	0.04 Avg Ratebase increase YoY for FERC Trans. is \$700M Higher in '16
Interest Expense	(0.01) Issued \$350Mn (2.7%) and \$350Mn (3.65%) at Parent on Nov. 24
Effective Tax Rate	- ~38% ETR; in-line with 2015
Callaway Refueling Outage	- Impact of Callaway Nuclear Refueling Outage During Spring 2016
Impact of Noranda	(0.02) Forgone sales net of mitigation; still partial operations in 1Q16
Absence of 1Q15 ICC Power Usage Item	(0.04) Removing Impact of ICC Recovery
Change in O&M, D&A, and Other	0.01 Organic cost inflation offset by lean initiatives in Missouri
<b>1Q16E Adjusted EPS</b>	<b>\$0.34</b>
<b>1Q16 Consensus</b>	<b>\$0.44</b>
<b>2016 UBSe EPS</b>	<b>\$2.48</b>
<b>2016 Consensus</b>	<b>\$2.53</b> 5-8% EPS CAGR from 2016 Adj. - 2018E
<b>2016 Guidance</b>	<b>\$2.40-\$2.60</b>

Source: Company filings, FactSet, UBS estimates

*For additional context, please refer links to relevant recent reports below:*

[3/10/16 Working Together This Time](#)

[11/6/15 Solid Execution Continues](#)

[8/4/15 Following The Regulatory Path to Illinois Growth](#)

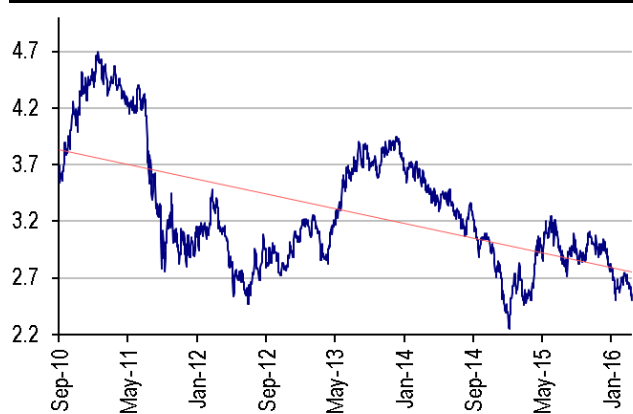
[5/8/15 Show Me the Growth in Missouri](#)

[2/25/15 Floating Down The Illinois River](#)

[11/7/14 Robust and Regulated](#)

[10/24/14 How Low Could Transmission ROEs Go?](#)

**Figure 58: 30-Year Treasury Rate (Long-Term)**



Source: FactSet

**Figure 59: 30-Year Treasury Rate (4Q15)**



Source: FactSet

## **What are the pivotal questions for AEE?**

### **What are the opportunities to improve Missouri earnings?**

- **Missouri legislation continues to wind through the halls:** House Bill 2689 was first introduced on March 8<sup>th</sup> and passed on April 7<sup>th</sup> 142-4 and was subsequently introduced into the Senate on April 11<sup>th</sup> with public hearings held the following day (April 12<sup>th</sup>). The separate Senate Bill 1028 was first read on February 3<sup>rd</sup> and the Senate Commerce, Consumer Protection, Energy and the Environment Committee voted 7-2 to pass the bill on March 31<sup>st</sup> and is now currently on the formal calendar for the Senate but it is unclear when it gets taken-up for review. The Senate has the ability to filibuster the bill (unlike the House) so we view this as the more critical body to watch for further updates. There is also the possibility that the bill can be amended while on the floor for review. Ameren has commented that it is optimistic that the bill could be taken up and debated by the Senate.

The bill has support from state Republicans and political sponsors as evidenced by the 142-4 affirmative vote. The largest industrial and utility supporters of the bill remain the bankrupt Noranda Aluminum and Ameren Missouri along with the other local utilities such as Empire District Electric and Great Plains Energy. We believe it is possible the legislation passes this year as long as there are minimal legislative obstacles to overcome houses. The key question remains timing – and the latest committee passage keeps it on pace to remain a possibility.

Stakeholders have pointed to Ameren Illinois rate decreases under the Energy Infrastructure Modernization Act (EIMA) in recent years as supportive for the Missouri legislation which includes many similarities

Despite these positive developments, there have been obstacles. Senate President Pro Tem Ron Richard expressed doubt whether the legislation would be approved this sessions stating that he was “not comfortable with anything yet”. The Missouri PSC testified in the House that the legislation was significantly different from the current rate regime, which could result in ~6% annual rate increases. Other large industrial users such as Anheuser-Busch have opposed the potential legislation as well.

#### **Key components of the Senate Bill include:**

- (1) Recovery of transmission costs in the fuel adjustment clause [FAC], which was adversely changed for Ameren in its last ratecase
- (2) Creation of performance- and formula-based ROE which transfer of the utility is involved in M&A
  - a. ROE set at 9.45% subject to changes based on US treasuries and a +/- 20bp band for performance against predetermined metrics
  - b. Limits on performance-based rate increases:
    - i. 2% annual increases in first two years
    - ii. 4.75% annual increase in years three and onward
    - iii. 3.75% average annual increase over the term of the tariff with a PSC reporting requirement by YE 2023
  - c. 47-53% equity ratio band on performance-based rates; (4) requirement to annually file a five-year plan with the PSC
- (3) Reforms for net metering compensation and interconnection review period [change from credit at the avoided cost rate vs. customer rate]. Solar rebates will be available for residential and small C&I customers with utility recover through base rates
- (4) Reforms for aluminium smelters through YE26.
  - a. Utility and aluminium smelters have the option to submit an application adjusting the rate for the aluminium smelter. The rate is contingent on maintaining employees at least equal to 1.5x the MW demand. We expect Noranda to request one flat rate for the entire year rather than a higher rate in the summer and a lower rate in the winter.
  - b. Aluminium smelters (ex. Noranda) are excluded from the performance-based rate provisions

Please refer to links below for more details on the proposed legislation:

[Missouri House Bill \(HB\) 2689](#)

[Missouri Senate Bill \(SB\) 1028](#)

#### **What are the opportunities to improve Missouri earnings?**

- **When is the next ratecase? Later in 2016:** Following the Noranda news, Ameren filed a notice with the Missouri PSC which would allow it to file a ratecase any point after mid-March to address the lost revenues from Noranda from other customers. The possibility of the ratecase introduces additional risks to the story and could impact the cost cut plan in the near-term. On the 4Q16 earnings call management stated that the filing would be in 2016 but is waiting for the outcome of the legislative session before making the filing. Ideally if the legislation discussed above is approved then management could implement some of the elements in its ratecase. If the legislation is unsuccessful then we still expect a ratecase to recover for lost sales as a result of the Noranda curtailment. Ameren can also request an Accounting Authority Order (AAO) separately from the ratecase in the interim rather than updating the revenue requirement in the upcoming full ratecase filing.

**Another ratecase is a risk.**

**If the legislation is approved the rate filing could be in ~August to capture new elements of the legislation. Conversely if the legislation is unsuccessful then Ameren could file for a ratecase shortly after the session ends in mid-May but may wait with the veto session beginning in Sept.**

- **Illinois rate filing will request a decrease:** In its latest formula rate filing under the EIMA Ameren expects a \$14Mn rate decrease which is driven primarily by the roll-off of charges for prior under-recovery. Based on the formula we would expect the ROE is lower YoY but with ratebase higher, we do not anticipate the rate decrease to translate to lower EPS.

### What do the latest Westar media reports indicate?

- **In surprising twist, AEE is reportedly interested in Westar:** On April 8<sup>th</sup> Bloomberg reported that Ameren was among parties bidding for Westar; while coherent in the near adjacency of the service territories, we saw the news as surprising. AEE has recently established a new growth rate of 5-8% with recent 4Q results, rolling forward expectations ahead of Street expectations with a top- quartile ratebase growth profile of 6.5%. Many companies of late exploring transactions have largely had earnings deficiencies in which they failed to meet their earnings growth targets, seeing a levered deal as an alternative to reducing expectations. Further details are available in the Westar section of the note but we also see a risk that the Missouri Public Service Commission could impute the holding company leverage when calculating the authorized equity ratio which would reduce the economics of any deal. The article further suggests the bid could include yet another Canadian entity (Borealis) following a similar bid on neighboring Empire District by Canadian company Algonquin in recent weeks.

## Maintaining EPS Estimates and Valuation

We are essentially maintaining our EPS estimates where we project a ~7.0% 2016 Adj.-2020E EPS CAGR. While the midpoint of management's 5-8% EPS CAGR does not assume ROE improvement from the 30-year treasury, we reduced our numbers in March when we adjusted our projects for Missouri O&M reduction among other factors.

The big question is the net earnings impact of incremental capex (positive) and bonus depreciation (negative)

Figure 60: AEE EPS Estimates

Consolidated EPS Projections	2014A	2015A	2016E	2017E	2018E	2019E	2020E	CAGR 'Adj.16-'20E
Ameren Missouri	1.60	1.62	1.39	1.56	1.60	1.63	1.66	2.3%
Ameren Illinois	0.82	0.88	0.94	1.05	1.17	1.31	1.47	11.7%
ATXI	0.06	0.13	0.22	0.26	0.30	0.33	0.37	13.9%
Other	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	(0.07)	
<b>Total EPS</b>	<b>2.40</b>	<b>2.56</b>	<b>2.48</b>	<b>2.80</b>	<b>3.00</b>	<b>3.20</b>	<b>3.43</b>	<b>6.9%</b>
Prior	2.40	2.56	2.50	2.80	3.00	3.20	3.43	
YoY Growth Rate	15%	6%	-3%	13%	7%	7%	7%	
<b>Consensus</b>	<b>2.40</b>	<b>2.56</b>	<b>2.53</b>	<b>2.82</b>	<b>3.06</b>	<b>3.22</b>		
<b>Projected ROEs, by Utility (regulatory basis)</b>								
Missouri	10.56%	10.58%	9.00%	9.89%	9.93%	9.94%	9.92%	
Illinois (wld avg Utes & Transmission)	<u>9.13%</u>	<u>9.71%</u>	<u>9.71%</u>	<u>9.77%</u>	<u>9.75%</u>	<u>9.75%</u>	<u>9.74%</u>	
Weighted Average ROE Earned (regulatory)	10.06%	10.25%	9.22%	9.86%	9.87%	9.88%	9.86%	
<b>Guidance 5%-8% off normalized 2016 \$2.63 (excludes lost -\$0.13 from Noranda)</b>								
Low Implied Guidance Range (5%) off normalized 2016 \$2.63			2.40	2.76	2.90	3.04	3.20	
High Implied Guidance Range (8%) off normalized 2016 \$2.63			2.60	2.84	3.07	3.31	3.58	
'16-'20 UBS EPS CAGR off normalized 2016 \$2.63								6.9%

Source: Company filings, FactSet, UBS estimates

Our valuation is based on a 2018E sum-of-the-parts. We recently removed the discount that we have historically applied to Missouri on the basis of higher confidence in the passing of energy legislation in 2016.

**Figure 61: AEE Sum-of-the-Parts Valuation**

Ameren Sum of the Parts Valuation - 2018E UBSe									
All figures in US \$ million except per share data									
	EPS		P/E Multiple			Equity Value			
		Low	Peer Multiple	Prem /Disc	Base	High	Low	Base	High
Ameren Missouri	1.60	15.0x	16.0x	0.0x	16.0x	17.0x	\$5,843	\$6,233	\$6,622
Ameren Illinois	1.17	15.5x	16.0x	0.5x	16.5x	17.5x	\$4,421	\$4,706	\$4,991
Ameren Transmission (ATXI)	0.30	16.5x	16.0x	1.5x	17.5x	18.5x	\$1,187	\$1,259	\$1,331
Parent Unallocated Items	(0.07)	15.0x	16.0x	0.0x	16.0x	17.0x	(\$251)	(\$268)	(\$285)
<b>Total / Implied Utilities</b>	<b>3.00</b>	<b>15.3x</b>			<b>16.3x</b>	<b>17.3x</b>	<b>\$11,200</b>	<b>\$11,930</b>	<b>\$12,660</b>
2018E Number of Shares Outstanding (Mn)							244	244	244
<b>Equity Value per Share</b>							<b>\$46.00</b>	<b>\$49.00</b>	<b>\$52.00</b>

Source: Company filings, FactSet, UBS estimates

# American Electric Power

*Large miss on mild weather, the elimination of Retail Stability Rider (RSR) payments in June 2015, and lower power prices.*

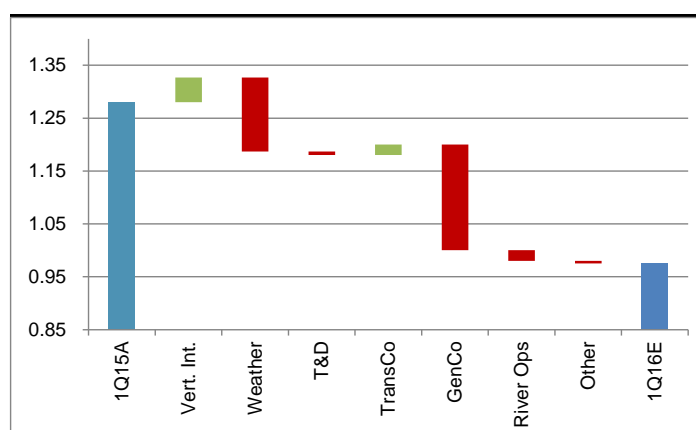
We expect a wide miss for 1Q16 at **\$0.98** vs. consensus \$1.15, driven largely by the mild weather and an expected reduction in merchant GenCo earnings as a result of the loss of RSR payments and lower capacity revenues in June 2015, the absence of a few pennies of positive contract mark to market in 1Q15, and lower power prices this year. This is partially offset by positive \$0.06 from rate increases and \$0.02 from higher transmission ratebase.

Figure 62: AEP 1Q16 vs. 1Q15 Walk

<b>1Q15A Adjusted EPS</b>	<b>1.28</b>
<b>Vertically Integrated Utilities</b>	<b>(0.09)</b>
Rate Changes	0.06
West Virginia: \$79Mn net increase 6/1	0.02
AEP Ohio: Dist Investment Rider	0.01
Oklahoma interim rider	0.02
KPCo: \$45.4Mn net increase 7/1	0.02
O&M	-
AFUDC	(0.02)
Weather	
Return to Normal	(0.09)
Current Quarter	(0.05)
Off-System Sales (OSS)	(0.01)
Absence of reg provisions (at KPCo and APCo)	(0.03)
Normal Load	-
Depreciation and Other	-
<b>Trans. &amp; Distribution Utilities</b>	<b>(\$0.01)</b>
Rate Changes	0.01
O&M	-
Depreciation	(0.01)
Normal Load & OSS	(0.01)
<b>Transmission HoldCo</b>	<b>\$0.02</b>
<b>Generation &amp; Marketing</b>	<b>(\$0.20)</b>
<b>AEP River Operations</b>	<b>(\$0.02)</b>
<b>Corporate &amp; Other</b>	<b>(\$0.01)</b>
<b>1Q16E Adjusted EPS</b>	<b>\$0.98</b>
<b>1Q16 Consensus</b>	<b>\$1.15</b>
<b>2016 Guidance</b>	<b>3.60-3.80</b>
<b>2016 UBSe</b>	<b>\$3.80</b>
<b>2016 Consensus</b>	<b>\$3.70</b>

Source: Company filings, FactSet, UBS estimates

Figure 63: AEP 1Q16 vs. 1Q15 Walk



Source: Company filings, UBS estimates

## Increased capital forecast financed with bonus depreciation; more to come

On the 4Q15 call, capital spending for 2017-2018 was raised to \$5B/yr from prior guidance \$4B/yr, with about \$1.6B of the increase from transmission investment. Funding for the increase is expected to come from deferred taxes resulting from the recent 5-year extension of bonus accelerated depreciation. Management continues to forecast no block equity from 2016-2018 and with \$2.9B of extra cash over the period, is also projecting \$1.1B of reduced overall capital requirements, available for debt reduction or other uses.

## Increased estimates for PPA, offset by weather and lower power prices

We recently raised our 2016 estimate \$0.04 and 2017-2019 estimates about \$0.14 to reflect incremental revenues from the Ohio PPA, partially offset by lower power pricing at Genco for the remaining uncontracted fleet and the effect of mild weather in 1Q16 as well. This places our 2016 estimate at the top end of guidance for 2016, which remains unchanged since it was raised at the EEI conference in Nov to \$3.60-\$3.80 from \$3.45-\$3.85 vs. UBS estimates \$3.76 and cons \$3.71. Our 2017-2019 estimates are now also at the top end of company guidance for 4%-6% long-term EPS growth off original 2014 guidance of \$3.20-\$3.40. Although management may choose to wait until 3Q Summer results to fully raise guidance, we would not be surprised to see at least a partial raise on the 1Q call given the large impact.

As we incorporate the effect of the PPA, our forward estimates are about \$0.14 higher, now a dime above consensus

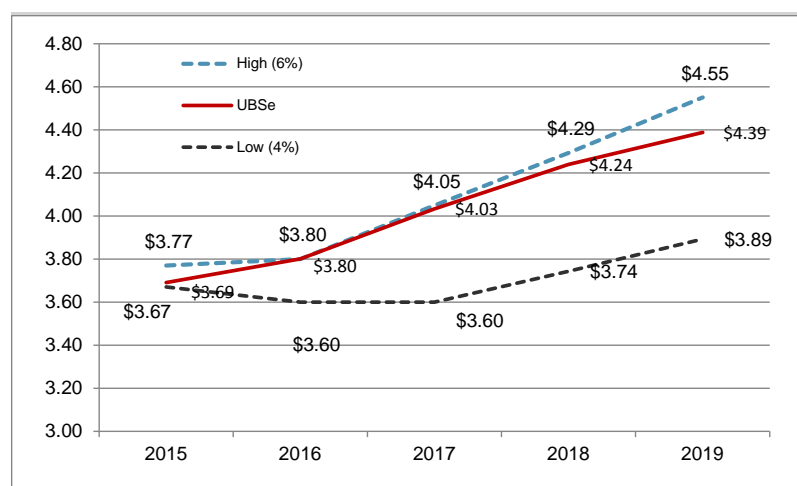
Although management may choose to wait until 3Q Summer results to fully raise guidance, we would not be surprised to see at least a partial raise on the 1Q call given the large impact

Figure 64: AEP Estimates vs. Guidance and Consensus, 2014A-2019E

EPS	2014A	2015E	2016E	2017E	2018E	2019E
<b>Total Utilities</b>	\$ 2.29	\$ 2.86	\$ 3.09	\$ 3.01	\$ 3.08	\$ 3.12
Transmission Holdco	0.31	0.39	0.50	0.69	0.83	0.95
<i>Transmission Guidance</i>		0.40	0.50	0.66-0.69	0.77-0.83	0.87-0.96
AEP River	0.10	0.06	-	-	-	-
Genco	0.50	0.51	0.31	0.40	0.42	0.42
Corp & Other & eliminations	0.22	(0.13)	(0.10)	(0.08)	(0.10)	(0.10)
<b>Consolidated</b>	\$ 3.43	\$ 3.69	\$ 3.80	\$ 4.02	\$ 4.24	\$ 4.39
<i>Prior estimates (Jan 2016)</i>	3.43	3.69	3.76	3.91	4.10	4.25
<i>Consensus</i>			3.70	3.90	4.15	
<i>Guidance EPS CAGR 4%-6% from \$3.30 midpt of orig 2014 guidance thru 2018E</i>						5.9%
<i>Guidance</i>			3.60-3.80			

Source: UBS estimates, company filings, FactSet

Figure 65: UBS estimates vs. Guidance, 2015A-2019E



Source: UBS estimates, company filings

## Maintain \$72 PT

For valuation, we recently rolled forward to a 2018E sum-of-the-parts analysis. With most of its ratecases completed and a significant improvement in earned ROEs for KY and WV expected for 2016, we apply a 5% premium to the average 2018E peer P/E multiple to the utilities.

Figure 66: AEP SOTP Valuation

American Electric Power								
Sum-of-the-Parts Analysis	2018E EPS	P/E & EV/EBITDA Multiples						
Utilities:	EPS	Low	Base	Premium	High	Low	Base	High
Vertically Integrated Utilities	\$3.08	14.5x	16.5x	5%	17.5x	\$ 23,322	\$ 26,539	\$ 26,807
Transmission Utilities	\$0.83	15.5x	17.5x	0%	18.5x	\$ 6,427	\$ 7,256	\$ 7,671
Parent & Other	-\$0.10	15.5x	16.5x	5%	17.5x	\$ (781)	\$ (832)	\$ (840)
Total Regulated Equity Value	<u>\$3.82</u>	15.3x	17.4x	5%	17.7x	\$ 28,967	\$ 32,963	\$ 33,637
					Value/sh	\$ 58.33	\$ 66.37	\$ 67.73
Genco Valuation	EBITDA	Low	Base	(Discount)	High	Low	Base	High
PPA Assets (open EBITDA)	\$59	5.0x	7.0x	0%	8.0x	\$ 295	\$ 413	\$ 472
Non-PPA Assets (open EBITDA)	\$303	5.0x	7.0x	0%	8.0x	\$ 1,516	\$ 2,122	\$ 2,426
Less: Net Debt						\$ (826)	\$ (826)	\$ (826)
Total GenCo Equity Value						\$ 985	\$ 1,709	\$ 2,072
					Value/sh	\$ 1.98	\$ 3.44	\$ 4.17
Incremental PPA Value Over Open EBITDA (from table)						\$ 1,017	\$ 1,080	\$ 1,112
					Value/sh	\$ 2.05	\$ 2.17	\$ 2.24
<b>Non-PPA Fleet Sale Impacts:</b>								
Base Case:								
Plus: Accretion from sale of non-PPA assets only ( <u>share repo</u> )							\$ (0.19)	
High Case:								
Plus: Accretion from sale of non-PPA assets only ( <u>reinvest in transmission</u> )								\$ 2.34
Shares Outstanding (2018E)						497	497	497
<b>Total Value per Share</b>						<b>\$62.00</b>	<b>\$72.00</b>	<b>\$76.00</b>

Source: Company filings, FactSet, UBS estimates

As noted above, our base-case open-EBITDA EV for the merchant fleet is 7x EBITDA offset by \$826M of net debt to get to an equity value of \$1.7B (\$3.44/sh). This includes the dual effect of higher capacity pricing offset by lower forward power pricing at AD Hub.

We then add extra value for our Base case scenario for a PPA worth an incremental \$2.34/sh (**see table below**), with the sale of the remaining non-PPA fleet at 7x EBITDA for an EV of ~\$2.1B offset by \$826M of net debt. When these proceeds are used for share repurchases, we see virtually no incremental value (slight dilution). However, as we note in our high-case scenario, when we assume that the \$1.3B of non-PPA fleet equity value is reinvested in transmission assets at a 10.84% ROE, this results in \$2.34/sh of equity value accretion (rather than - \$0.19/sh).

**We now see the sale of the remaining non-PPA fleet at 8x EBITDA for an EV of ~\$2.1B**

**Figure 67: Value/sh Accretion From Sale of Non-PPA Assets**

<b>Equity Value</b>		<i>non-PPA only</i>
EBITDA (2018E)	\$	303
EV/EBITDA		7.0x
EV		2,122
Debt		(826)
Equity		1,296
Equity Value/sh	\$	2.61
<b>Sale Accretion - Share Repurchases</b>		
Shares Bought Back (M)		19.9
Repo value on Buyback (Value/sh)	\$	2.42
<b>Accretion/sh vs. \$2.61 above</b>		<b>\$ (0.19)</b>
<b>Sale Accretion - Reinvestment in Transmission</b>		
Equity	\$	1,296
Net Income at 10.84% ROE	\$	141
Value at 17.5x multiple	\$	2,459
Value/sh	\$	4.95
<b>Accretion/sh vs. \$2.61 above</b>		<b>\$ 2.34</b>
Previous calculation (Jan 2016)	\$	3.20

Source: UBS estimates, company filings, FactSet

**Figure 68: Value/sh Accretion from PPA**

<b>PPA Assets (open EBITDA)</b>		
EBITDA (2018E)	\$	59
EV/EBITDA		7.0x
EV		413
Debt		-
Equity		413
Equity Value/sh	\$	0.83
<b>Incremental value of PPA</b>		
Ratebase (\$M)	\$	1,600
ROE		10.38%
Equity %		50%
Ratebase Net Income (\$M)	\$	83
Absence of OVEC OSS loss	\$	7
Net Income	\$	90
P/E		16.5x
Equity	\$	1,493
Equity Value/sh	\$	3.01
<b>Accretion/sh vs. EV/EBITDA</b>		<b>\$ 2.17</b>
Previous calculation (Jan 2016)	\$	1.55

Source: UBS estimates, company filings, FactSet

*For more detail on these issues, please see our other recent reports:*

[3/31/16 Scoring a contract](#)

[1/29/16 Bonus Appreciation](#)

[12/15/15 Another Big Splash in Ohio](#)

[12/7/15 Buying into Ohio](#)

[10/26/15 Love it or List it...Ohio Edition](#)

[9/18/15 Embedding the Auction Uplift](#)

[7/24/15 Marching to a Regulated Tune](#)

[4/27/15 Powerful Start to an Uncertain Year](#)

[3/19/15 More March Madness in Columbus](#)

[2/25/15 Purchase Power Placeholder](#)

## **PUCO approves both AEP and FE contracts with minimal changes**

On March 31<sup>st</sup>, the Public Utilities Commission of Ohio (PUCO) approved the power purchase agreement (PPA) and retail rate stability (RRS) rider components of AEP and FE's pending Electric Security Plans (ESP) with modifications. For FE, the PUCO mandates no total bill increase for the first two years but while AEP's rider mechanism cannot cause more than 5% inflation with any 'capped' compensation subject to deferral beyond the period (i.e. no compensation is permanently forgone by the companies). We detail what we see as the primary Commission modifications on page 2 but we do not believe any of the alternations are significant enough to have a material negative impact on the economics for either FE or AEP. Another notable modification to the Order is that AEP can seemingly no longer recover the conversion costs for Conesville 5 & 6 (~530MW net owned capacity).

## Muted response for shares following approval highlights investor concerns

The vast majority of investors we have spoken with expected the PUCO to approve the PPA/RRS riders so we are not surprised by the lack of response in shares. The real question will be whether the riders can withstand FERC/judicial scrutiny with merchant generators already having pledged to challenge the contracts. The FERC does not have a mandatory timeframe to respond to the latest 206 complaint filed in early February. We continue to see challenges around the 'Affiliate Rules' (Edgar/Allegheny standards) as a key risk that could restrain the performance of shares in both FE and AEP (albeit much more significantly the former given the implications on its balance sheet). Ultimately if the FERC rejects the agreements on the basis that contracts were not executed in a sufficiently independent manner between affiliates, the parties including FE and AEP could push the subject in other ways, seeking other structures with settling parties if not legislation outright to allow for re-regulation in the state.

## PUCO pushes back on PJM and MOPR requesting uniformity of rules

The PUCO specifically addressed PJM's brief regarding minimum mandated bidding (minimum offer price rule [MOPR]) behavior by essentially stating that it believes PJM should apply the standard to all plants rather than applying different rules to just these assets. We believe it is unlikely that PJM will pursue this angle for regulated and quasi-regulated/public assets given the lengthy stakeholder process but the market monitor could make a complaint directly at the FERC level.

## What was modified in the order?

Following the Order management issued a press release stating that it was "moving forward" on the PPA.

- **Rate impact mitigation:** The rate increase from the PPA rider cannot exceed 5% of the June 1, 2015 SSO rate plan through May 31, 2018 for specific customer classes (not overall). Similar to FE above, if the PPA rider charge is curtailed at the 5% cap, any additional under-recovery would be referred into a future period.
- **Retirement or conversion costs:** Customers will not pay for plant retirement or conversion costs for the PPA units via the PPA rider or another mechanism. This appears to be one of the more significant changes where AEP had previously agreed to convert Conesville Unit 5 & 6 to be dual-fuel (adding gas) with recovery from customers. AEP owns 71% of Conesville where Units 5 & 6 are each 375MW. We view this change as indicative of Commission concerns that it was potentially pushing too far towards a regulated paradigm.
- **No liquidated damages if court system strikes down the rider:** If the PPA is ultimately rejected in the judicial system that action would not trigger liquidated damages.
- **No recovery of credit commitment:** AEP cannot recover the \$100Mn credit commitment that it made in any PUCO venue.

**AEP's press release reiterated that it will "retire, refuel, or repower" Conesville units 5 & 6**

## Finally Pushing Forward on Merchant Auction

On March 24<sup>th</sup>, media reported that AEP has begun a long-awaited auction of its Ohio and Indiana merchant plant fleet that is not included in the proposed 8-year power purchase agreement (PPA) with Ohio. The plants up for sale produce ~80% of AEP's merchant EBITDA and include the 2.7-GW Gavin coal plant (Ohio), the 840-MW Waterford combined cycle plant (Ohio), the 507-MW Darby gas peaker (Ohio), and the 1.2-GW Lawrenceburg combined cycle in Indiana. As we've written previously, we expect an 8-12 week process finishing by July.

**We see the non-PPA Ohio merchant fleet worth about \$2.1B at 7x EBITDA**, offset by ~\$826M of net debt. While the latest reduction in trading multiples for IPPs has been sizable, we suspect private markets could yet look through the near-term overhang. Further, the bulk of the EBITDA is produced from the two CCGT units and a single peaker; we emphasize valuations between coal and gas assets in PJM increasingly appear to be in sharp contrast with each other.

**Asset value build up.** Applying the ~\$900/kW from the latest TLN CCGT deal to the ~2GW of CCGT (although recent datapoints including TransCanada's own remarketing of that asset would suggest downward pressure on that figure), ~\$300/kW to Gavin, and ~\$300/kW to the Darby peaker would yield closer to \$2.8-3.0 Bn depending on further value ascribed to retail segment and remaining ~48MW hydro plant. The biggest wild card remains uncertainty on valuation applied to the 2.65GW Gavin coal plant.

**But we assume a conservative ~breakeven starting point.** We generically see little accretion from the sale of the non-PPA assets in a conservative scenario of just repurchases. More realistically, we see some proportion of investment driving some portion into transmission. As we illustrate in the tables above, this could drive accretion closer to \$2.34/sh for AEP. We emphasize AEP's transmission opportunities are differentiated from peers, seeing much of the contemplated spend as outside of the usual RTO planning process which has disappointed elsewhere. Rather, spend for AEP appears more intact, with the key the pace at which management can deploy proceeds.

## Utilities turning the corner?

On June 22<sup>nd</sup>, AEP's settlement for Kentucky Power was approved (was filed on April 30<sup>th</sup>) for a -\$23M base rate reduction based on a 10.25% ROE and 43.93% equity. This compares to -0.1% for TTM ROE in 3Q15, 4.2% for FY15 and guidance for 8.6% for FY16. However, while the base rate was reduced, this is more than offset by increases for \$68.4M of various rate riders, including a rider to recover retirement costs for the Big Sandy coal plant retirement, another for remaining non-fuel operating costs for Big Sandy, and an Environmental Surcharge rider for equipment installation at the Mitchell plant. As a result of the riders, we expect a marked improvement in ROE for 2016.

In West Virginia, APCo received a \$99M rate increase in June 2015 based on a 9.75% ROE and 47.16% equity for \$3.7B of ratebase and a 2013 test year (average). This compares to 9.4% ROE in 2015 and guidance for 10.7% for 2016. However, within APCo, WV has typically been earning closer to ~5% ROE, so we expect the rate increase to result in a significant forward improvement there.

As a result of the riders, AEP expects a marked improvement in ROE for 2016

All quiet? No meaningful ratecases for time being

Figure 69: ROE Guidance: 2016 vs. 2015 vs. TTM Sept vs. Authorized

	ROEs TTM		AEP Guide	Auth ROE	Ratecase comment
	Sep-15	Dec-15	2016 Jan-16		
Ohio Power	11.8%	11.6%	11.9%	10.20%	PPA decision 1H16
APCo	8.9%	9.4%	10.7%	10.20%	WV 9.75%, VA 10.4%-11.4%
KPCo	-0.1%	4.2%	8.6%	9.80%	\$45M net rate hike June 2015.
I&M	9.8%	10.2%	9.9%	10.20%	Cook lifecycle mgmt recovered in riders until rate filing ~2018
PSO	9.2%	8.6%	9.0%	9.85%	Filed for 10.5% ROE on 7/1/15
SWEPCO	9.3%	9.0%	7.8%	9.97%	
AEP Texas	9.9%	8.4%	8.7%	9.96%	
Transmission Holdco	11.3%	11.1%	10.2%	11.49%	Earned ROE includes leverage at the T-Holdco subsidiary, but not at parent
Average	9.4%	9.6%	10.1%	10.3%	

Source: Company filings, regulatory filings

- **(More) Smartmeters coming?** Following on FE's settlement/order which requires a filing for smart-meter deployment, we see upside to our core capex estimates for AEP as well. With potential opportunity to scale from its current pilot, we suspect this could well prove a substantial accelerator of ratebase growth in Ohio (and incremental use of GenCo proceeds). A proposal to scale its pilot was submitted over a year ago before the PUCO.
- **Oklahoma rate filing.** On July 1, 2015, AEP filed a new base rate request in Oklahoma for an \$84M increase based on a 10.5% ROE for 48% equity on \$2.062B ratebase. An additional \$44M increase through an environmental compliance rider was also requested. On October 14<sup>th</sup>, Staff recommended a \$32M increase based on a 9.25% ROE and on January 1<sup>st</sup>, PSO implemented a \$75M interim rate increase as allowed by law. The company earned 8.6% ROE in 2015 and expects to earn a 9.0% ROE in FY 2016E vs. the currently authorized 9.85% ROE. We expect final rates in place in 1H16.
- **Shale territory elec sales still growing strong.** As noted for several quarters, the oil and gas sectors in Ohio have been hit by lower pricing, but the sector is proving surprisingly resilient, resulting in a 10.5% increase in 4Q load year-over-year in AEP's shale counties (vs. 9.7% in 3Q15). The auto sector is also showing strength. Non-oil/gas customer sales declined for the fourth quarter in a row by -5.3% in 4Q (vs. -3.1% in 3Q15), with much of this weakness centered more in AEP's western jurisdictions (i.e., TX). In particular, we note what appears to be a stabilization and steady improvement this year for industrial electric sales in the Woodford, Permian, Eagle Ford, and Marcellus shale basins. *We emphasize a further weakening in shale-related sales across its territories (particularly in Utica-exposed Ohio territory) is the most commonly cited investor pushback on the concern.*

Figure 70: AEP Weather Normalized GWh Sales Growth YoY and 2016 Guidance

	1Q13	2Q13	3Q13	4Q13	2013	1Q14	2Q14	3Q14	4Q14	2014	1Q15	2Q15	3Q15	4Q15	2015A	Prior 2015E	2016E
Residential	1.3%	-0.1%	-1.8%	0.9%	0.0%	4.4%	-1.5%	-1.1%	2.1%	1.1%	-4.0%	0.3%	0.8%	-4.0%	-1.8%	0.2%	0.5%
Commercial	0.5%	-2.2%	1.2%	0.2%	-0.1%	2.9%	0.4%	0.2%	3.5%	1.7%	-0.4%	1.9%	1.3%	-3.9%	-0.2%	-0.4%	0.9%
Industrial	-3.6%	-3.0%	-1.2%	1.6%	-1.6%	2.2%	4.5%	4.8%	3.9%	3.9%	1.2%	0.6%	0.7%	-3.3%	-0.2%	2.0%	1.1%
Total	-1.5%	-2.7%	-1.5%	-0.8%	-1.6%	1.5%	-0.5%	0.1%	3.0%	1.0%	-1.3%	0.9%	0.9%	-3.7%	-0.8%	0.6%	0.9%
Total Ex-Ormet	-0.6%	-1.9%	-0.7%	0.9%	-0.6%	3.2%	1.3%	1.1%	3.1%	2.2%							

Source: Company filings

- **Reduced O&M for 2016.** Following the previous two years of accelerated ~\$74M operations and maintenance spending, management sees a reduction of about \$200M in 2016 to \$2.8B.

- **SWEPCO's plan to move Turk into ratebase likely a 2016 event (at the earliest).** Low natural gas pricing has apparently pushed a possible filing into 2016 at earliest while the company awaits a more favorable comparative market condition. In the meantime, with a large steel customer expected online this year, AEP intends to meet incremental demand through a patchwork of solutions, including market purchases.
- **Clean Power Plan (CPP) opportunities.** On the 4Q call, AEP reiterated its belief that states within its jurisdiction should file State Implementation Plans (SIP) for EPA's CPP by the September 2016 deadline, citing the need for industry clarity over investment decisions.
  - *Individual approach?* Management did not indicate it had intentions to coordinate its carbon reduction actions between its respective states. That said it did express a clear preference to file for a mass-based program, a bias we expect repeated in other states as they report their results in coming weeks.
  - *Not taking the litigated path.* Management emphasized it would *not* seek to interject significantly into forthcoming litigation after publication of the CPP rules in the federal register.
  - *What does CPP mean for AEP?* Management has been particularly shy to offer implications from CPP for the portfolio. We expect at least a looser sense to emerge in coming months.

# Avista Corp.

*In-line 1Q16 \$0.82 with decoupling in WA, ID, and OR leading to a positive weather comp vs. last year's mild temperatures. Also see a negative -\$0.03 impact from the ERM vs. last year's strong melt-off, offset by rate increases and sales growth.*

As a result of decoupling in both Washington and Idaho (Oregon joins them on March 1<sup>st</sup>), we expect an in-line 1Q at \$0.82 vs. consensus \$0.82, with a favorable weather comparison vs. last year's mild -\$0.08 hit. Rate increases also help another \$0.08, offset by higher O&M, D&A, and interest expense. We expect a negative year over year comparison for the Energy Recovery Mechanism (ERM), which booked a strong \$5.7M in 1Q15 as a result of high melting and runoff during last year's mild temperatures. Although 1Q16 is also mild, we have not seen similar levels of runoff this year.

**Figure 71: AVA 1Q16E vs. 1Q15A Walk**

1Q16E Earnings Walk	EPS
<b>1Q15 Adjusted EPS</b>	<b>\$0.74</b>
Weather	\$0.06
Sales Benefit	\$0.04
ERM Benefit	(\$0.03)
Rate Relief	\$0.08
AERC	\$0.00
O&M	(\$0.02)
D&A	(\$0.04)
Interest	(\$0.01)
Dilution	\$0.00
Other	\$0.00
<b>1Q16E Adjusted EPS</b>	<b>\$0.82</b>
Consensus	\$0.82
2016 UBSe	\$2.06
2016 Consensus	\$2.05
2016 Guidance	\$1.96-\$2.16

Source: UBS estimates, company filings, FactSet

**Figure 72: AVA Expected Rate Relief 1Q16**

Rate Relief (\$M)		
\$	16.9	WA - elec (Jan 1, 2016)
\$	1.7	ID - elec (Jan 1, 2016)
\$	2.5	ID - gas (Jan 1, 2016)
\$	4.5	OR - Gas (Mar 1 2016)
\$	5.3	OR - Gas (April 2015)
\$	30.9	pre-tax YoY impact
\$	20.1	after-tax (annual)
\$	0.08	1Q16 vs 1Q15 EPS

Source: UBS estimates, company filings, FactSet

*For further context, please refer to our recent notes:*

[3/18/16 Expecting Some Runoff \(d/g to Sell\)](#)

[2/26/16 Aiming for a Longer Rateplan](#)

[8/7/15 Steady Progress on Ratecases](#)

[5/7/15 Hydraulic Earnings Lift](#)

[3/2/15 Another Wet One?](#)

[12/22 Upgrade note "Moving Back to Neutral After the Noise"](#)

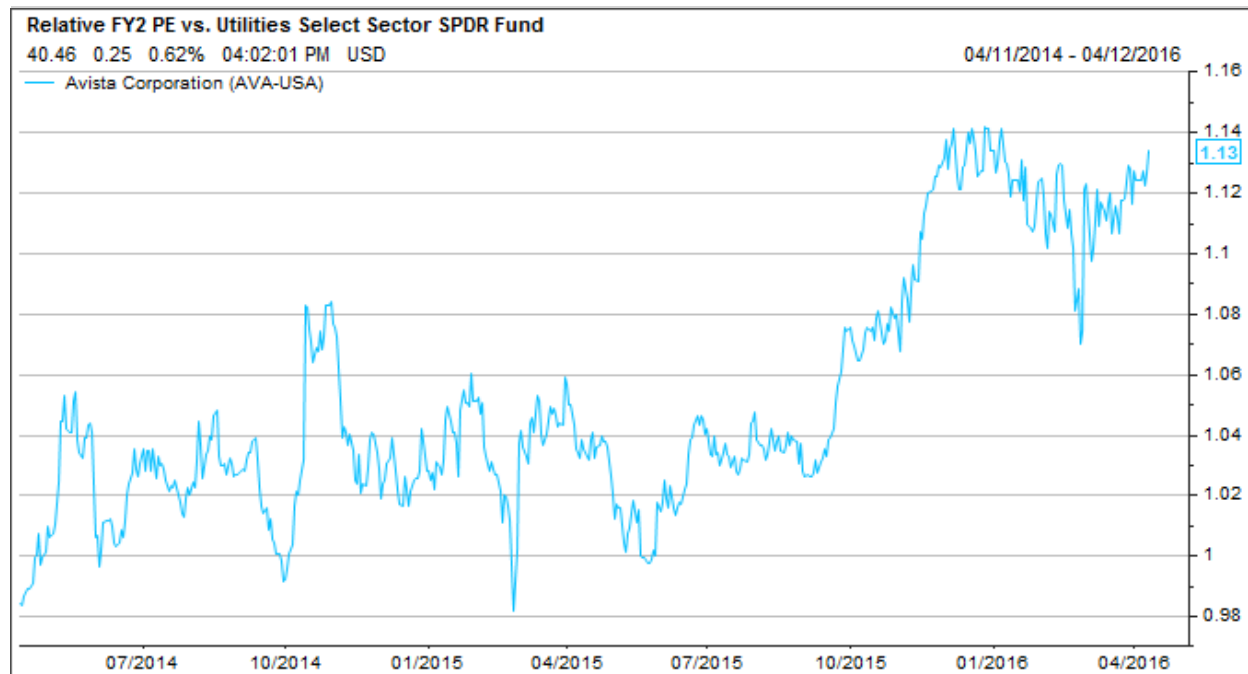
[12/19/14 The 'Smid Bid': The Context for Regulated M&A](#)

## Estimates, PT unchanged; reiterate Sell on unsustainably high relative 2018E P/E

Our estimates are unchanged. Our valuation remains based on a 2018E peer utility P/E, with AVA now trading at a 13% premium to peers (see 2-year chart below). Our 2016 estimate remains based on an 8.9% ROE and \$55M of equity raised this

year, along with an expected benefit from the ERM mechanism (up to \$0.04 at the top end of the \$4M deadband). We are maintaining our estimates (also an 8.9% ROE), which now reflect a 4.2% EPS CAGR off the \$2.06 midpoint of 2016 guidance (vs. management's target for 4%-5% earnings and dividend growth).

**Figure 73: AVA Forward 2-year P/E Relative to XLU, May 2014-April 2016**



Source: FactSet

## Debt/Equity for 2016

The December 2015 issuance of \$100M in 30-year mortgage bonds at 4.37% **is expected to be followed by a 2016** issuance of \$155M in long-term debt (including the refinancing of \$90M of long-term debt maturing in 3Q16) and \$55M in common stock based upon management's guidance. The consolidated equity ratio at year-end 2015 was 46.9%.

**\$55M equity planned for 2016**

**Figure 74: AVA 2016 Guidance vs. UBS estimates and Consensus**

2016 Guidance			
	Low	High	Midpoint
Avista Utilities	\$1.91	\$2.05	\$1.98
AEL&P	\$0.09	\$0.13	\$0.11
Other	(\$0.04)	(\$0.02)	(\$0.03)
Consolidated	\$1.96	\$2.16	\$2.06
Avista Utilities ROE guidance	8.6%	9.2%	8.9%
Incremental items not included in guidance:			
Weather YTD w/decoupling	\$0.00	\$0.00	\$0.00
ERM expectation (UBSe)	\$0.04	\$0.04	\$0.04
<b>UBSe</b>			<b>\$2.06</b>
<b>Consensus</b>			<b>\$2.05</b>

Source: Company filings, FactSet, UBS estimates

Figure 75: UBS estimates for AVA, 2014A-2019E – Consistent 4% EPS growth

AVA	2014A	2015E	2016E	2017E	2018E	2019E
<b>Segment EPS</b>						
Avista Utilities (WA, ID, OR)	\$1.83	\$1.81	\$1.97	\$2.04	\$2.13	\$2.23
AEL&P Utility (AK)	\$0.05	\$0.11	\$0.11	\$0.11	\$0.12	\$0.13
Ecova						
Other	\$0.05	(\$0.03)	(\$0.03)	(\$0.03)	(\$0.03)	(\$0.03)
<b>UBS Estimates</b>	<b>\$1.93</b>	<b>\$1.89</b>	<b>\$2.06</b>	<b>\$2.13</b>	<b>\$2.22</b>	<b>\$2.33</b>
Prior UBS estimate	\$1.93	\$1.89	\$2.06	\$2.13	\$2.22	\$2.33
Consensus			\$2.05	\$2.13	\$2.22	\$2.32
Guidance			\$1.96-\$2.16			
EPS CAGR Implied off 2016 guidance midpoint \$2.06 (LT guidance 4%-5%)						4.2%
ROE Earned at Utility (8.6%-9.2%, including 60-70 bps reg lag)			8.9%	8.9%	8.9%	8.9%

Source: UBS estimates, company filings, FactSet

## Favorable precipitation should again benefit the ERM for FY2016

Snowpack has so far been heavy this winter as a result of the El Nino effect, and there is still another few weeks of high-level snow accumulation possible. So far, the Northwest River Forecast Center predicts 86% water supply runoff from April through September for the Clark Fork River (where 75% of AVA's hydro depends upon) and 80% for the Spokane River. Depending on the timing of melt-off later this Spring (among many other power fleet factors), this is likely to have a positive effect on earnings from the Energy Recovery Mechanism (ERM). At this time, AVA expects to finish 2016 within the \$4M benefit dead-band (i.e., no sharing of benefits up to \$4M pretax). Importantly, none of this possible benefit is embedded within 2016 guidance. In the table below, we show our estimate of how a \$4M benefit might be distributed quarterly throughout 2016 (based roughly on historical results). In comparison, recall that warm weather in 1H15 caused a more rapid melt-off of snowpack vs. 1H14, when cold temperatures kept much of the snow frozen through to Spring. As a result of this, ERM benefits were significantly lower than normal in 1Q14 (with benefits pushed into 2Q14), while the rapid melt boosted 1Q15 benefits as more hydroelectric power was available for sale. For full year 2015, benefits exceeded \$10M pretax, although under the dead-band sharing mechanism, the ERM mechanism reached the 90%/10% sharing band, leaving the company's share at \$6.3M overall, with the remainder refunded back to customers. We emphasize that ERM results are heavily dependent on natural gas pricing and fleet dispatch decisions in addition to hydro conditions.

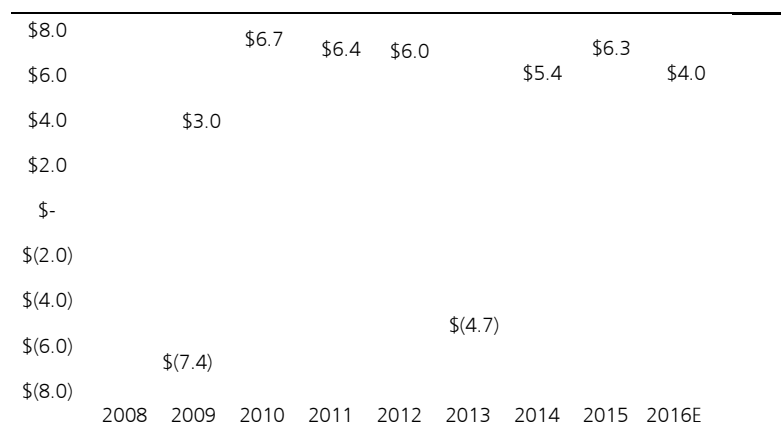
**Importantly, none of this possible benefit is embedded within 2016 guidance**

Figure 76: ERM Mechanism Earnings Impact (\$M), 1Q12A-4Q16E (UBS estimates)

ERM Mechanism Earnings Impact (\$M) (pretax)	2012A	2013A	2014A	2015A	2016E	Notes
1Q	4.2	3.1	1.3	5.7	2.5	Cold weax in 1Q14 (low melt). Heavy melt 1Q15.
2Q	0.9	1.0	3.6	-	0.9	Below normal precipitation 2Q15
3Q	0.8	1.9	0.4	(0.1)	0.5	Expect below normal hydro May-Aug 2015
4Q	0.1	(10.7)	0.1	0.7	0.1	Colstrip outage 4Q13
Yearend total	\$ 6.0	\$ (4.7)	\$ 5.4	\$ 6.3	\$ 4.0	Expect to be within the \$4M benefit deadband in '16

Source: Company filings, UBS estimates

**Figure 77: ERM Earnings Impact, 2008-2016E**



Source: Company filings, UBS estimates

## New 18-month rate plan filed in Washington

- **Rate decrease approved for Washington; approving attrition allowances within rates.** The partial settlement in May 2015 set a 9.5% ROE on 48.5% but left ratebase, O&M, and historic test year attrition on the table for the litigated process. The final order on January 6<sup>th</sup>, 2016 approves \$1.3B electric ratebase and \$264M gas ratebase (vs. AVA request of \$1.5B and \$286M, respectively), with a final electric rate decrease of only -\$8.1M instead of the ALJ proposal for -\$8.7M. The improvement is to recognize the need for revenues to offset historic test year attrition. Similarly, on the gas side, the approved increase was \$10.8M instead of the ALJ's \$10.0M. Rates went into effect on January 11<sup>th</sup>.
- **A new Washington ratecase was filed on February 19<sup>th</sup>** for a 9.9% ROE on 48.5% equity and an 18-month rate plan. Under the plan, AVA is requesting new rates on January 1, 2017 (\$38.6M elec and \$4.4M gas) followed by a second step-up in 2018 (\$10.3M elec and \$0.9M gas), with a rate increase stayout stipulating no new rate filing for rates effective prior to July 1, 2018.
- **Ratecase settlement approved in Idaho brings decoupling to nearly all jurisdictions.** The increase in revenue is based on a 9.5% ROE, with annual electric revenues increased by \$1.7M (0.7%) and gas increased by \$2.5M (3.5%). Rates went into effect on January 1, 2016. The key takeaway is the inclusion of decoupling mechanisms for both electric and gas, with AVA now decoupled in Washington, Idaho, and Oregon (more than 90% of total ratebase). Major capital projects in the filing include the multi-year redevelopment of the Little Falls and Nine Mile powerhouses, the replacement of IT infrastructure, and continued gas distribution line replacement. The request also includes a proposed electric and natural gas Fixed Cost Adjustment (FCA) mechanism (decoupling), where revenues would be adjusted each month based on the number of customers, rather than kilowatt-hour and therm sales, with surcharges and rebates to customers in the following year.
- **Gas rates were approved in Oregon on February 29<sup>th</sup>** for a \$4.5M rate increase and 9.4% ROE and 50% equity (vs. the original request for \$8.6M based on a 9.9% ROE and 50% equity). The order also includes the company's requested decoupling mechanism, whereby the company's natural gas revenues would be adjusted each month to reflect revenues based on the

Attrition allowances are now embedded in Washington rates

The key takeaway is the inclusion of decoupling mechanisms for both electric and gas, with AVA now decoupled in Washington, Idaho and Oregon (over 90% of total ratebase)

number of customers, rather than therm sales, with surcharges and rebates to customers in the following year.

- **A new elec/gas Idaho ratecase** is expected to be filed in 1H16.
- **Frequent rate filings have been the norm** as a result of the application of historic test years, we expect to hear from management whether the extra revenues granted would change that situation. *AVA remains long generating capacity and will not need another CT until 2020 (followed by another in 2023).*
- **No intermediate need for a ratecase in Alaska**, although management will continue to evaluate.

## LDC opportunity in Juneau moving slowly amid lower oil

AVA has proposed development of a local gas distribution utility in Juneau, Alaska, which would move the city away from its current reliance on diesel/elec for heating and diesel for electric generation. If approved, the company had been expected to move forward in 1H16. However, given the lower (more competitive) price of oil, the financial justification for customers to switch is somewhat eroded at this time. Furthermore, low oil prices have slowed the Alaskan economy and thus reduce headroom in rates for large infrastructure projects. In any event, management reports that no regulatory mechanism for recovery of an investment has yet been agreed upon. Should progress resume, management expects to invest \$130M in the project over 10 years, with the first two years (ideally 2016-2018) of construction being slightly dilutive to earnings, and turning accretive by the 3<sup>rd</sup> construction year (~2019). By year 5 (~2021), or 3<sup>rd</sup> year in operation, AVA anticipates the project would be \$0.05 accretive. To be successful, AVA intends to pursue a combination of low cost debt financing through the Alaska Industrial Development and Export Authority (AIDEA) and potential state/local funding to support customer conversion costs.

Unlikely to happen near term

The unemployment rate in Alaska was 6.6% in January 2016 versus 6.4% in January 2015 reversing a string of improving employment since the financial crisis. The Alaska Department of Labor and Workforce Development specifically cited job losses in oil/gas and construction as a key negative factor offsetting improvement in other areas of the economy.

## Salix selected as "top ranked project" for Fairbanks LNG

On March 3<sup>rd</sup>, Salix was selected as the [top-ranked proposal](#) for the [Fairbanks LNG Interior Energy Project](#), with project authorization expected on March 31<sup>st</sup> and a final investment decision by June 23<sup>rd</sup>. The ~\$110M opportunity is worth a more modest \$20M equity for Salix, with another \$40M from the state (AIEDA) and \$50M in project loans. Otherwise, we think other potential LNG transportation customers may be holding-off to evaluate needs after both the drop in global oil prices and to see how the EPA's latest Clean Power Plan shapes electric fuel costs and requirements (assuming the current Supreme Court's stay of the order is lifted).

**Further opportunities may eventually exist to ship LNG** to other parts of southeast Alaska as part of a conversion strategy away from diesel, especially considering poor hydroelectric conditions of late. AVA has also discussed opportunities for marine fuelling and bunkering and for transportation in Western North America.

# Calpine Corporation

## 1Q expectations should be a bit weaker

We forecast Calpine reporting adjusted EBITDA of **\$344Mn**, shy of the Street consensus (\$362Mn), as the YOY improvement over \$338Mn in 1Q15 is quite small. Aggregate hedge positions appear to suggest flat to some degradation in YoY results, coupled with a reduction in expected dispatch given improvement in Western hydrology. We emphasize the turnaround in drought conditions out West has put downward pressure on results. Following record 27TWh in 1Q last year we see potential for erosion based on further degradation in CCGT output of the Western portfolio (~1-2TWh possible judging from historicals). In its first full quarter owned by Calpine we estimate that Granite Ridge contributed ~\$10Mn at best given particularly mild Northeast weather.

**We expect results just shy of Street. The YoY uplift is principally driven by contributions from new assets**

**Figure 78: CPN 1Q16 Adj EBITDA Walk**

Calpine Corp 1Q16 EBITDA Walk			
1Q15A Adjusted EBITDA		\$338	
			Notes
<b>Capacity Price Changes</b>			
RA Payments (California)	-		
Non-California (PJM, etc.)	13		PJM Rolloff YoY, improvement in June
<b>Energy Margin</b>			
Geysers Outage	-		Geysers Deductibles Incurred, so insurance will roughly offset
Hedge Position	(5)		Open hedges declining substantially (except for PJM West)
Garrison CC	8		Full Quarter Contribution
Granite Ridge	10		Acquisition closed 2/5/2016
<b>Total Uplift</b>	<b>13</b>		
<b>Volumetric Improvement</b>	<b>(20)</b>		Generation Down Modestly Weak Weather / Hydro Returning to Normal in California
<b>Net Change</b>	<b>6</b>		
<b>1Q16A Adjusted EBITDA</b>		<b>344</b>	
<b>1Q15A Adjusted Consensus</b>		<b>\$362</b>	
<b>2016 UBSe EBITDA</b>		<b>1,915</b>	
<b>2016 Consensus</b>		<b>1,873</b>	
<b>2016 Guidance</b>		<b>\$1,800-\$1,950</b>	

Source: Company reports, ThomsonReuters, UBS estimates

## Capital allocation refocus

We expect management discussion to focus principally on debt reduction on the 1Q call, consistent with its 4Q15 call, as management looks to 'talk down' concerns around its slightly higher leverage vs. peers.

With 4Q results, Calpine reaffirmed its 2016E adjusted FCF guidance of \$710-\$865Mn (\$788Mn UBS estimates) which excludes ~\$800Mn growth capital for the Granite Ridge acquisition and York 2 which essentially erases positive organic free cash flow for the year. Management presents its 2016E available capital for allocation of \$1,750Mn which includes \$906Mn of 12/31/14 unrestricted cash on hand, \$166Mn of proceeds from the pending Osprey sale that will not be received until January 2017, and 2016E FCF (\$782Mn midpoint), less \$100Mn. If Calpine plans to utilize its net capital available remaining of ~\$535Mn it will by definition increase its reliance (but not necessarily borrowings) on the revolver to meet its internal liquidity (not cash) target.

**Figure 79: Calpine Capital Allocation Analysis**

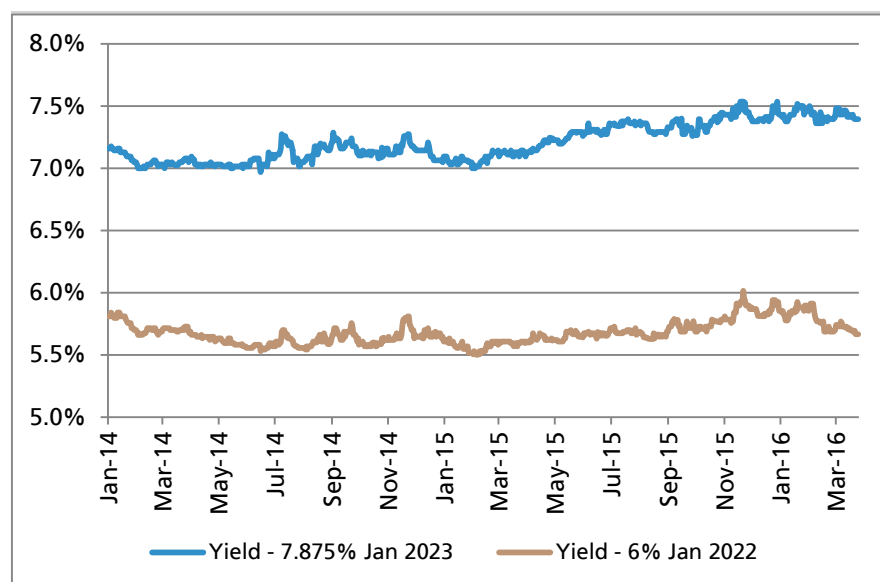
<b>Calpine Capital Allocation Analysis</b>		<b>2016E</b>
CPN Definition of Capital for Allocation		
12/31/15 Unrestricted Cash		906
Plus: 2016E FCF Generated (Midpoint)		783
Plus: 2017 Proceeds from Osprey Sale		166
Less: Minimum Cash balance		(100)
<b>Total Capital Available for Allocation</b>		<b>1,755</b>
Less: Growth Capex		
Granite Ridge Purchase		(500)
York 2 and Others		(285)
<b>Total Growth Capex</b>		<b>(785)</b>
Less: Debt Reduction		
Required Mandatory Debt Amortization		(210)
Committed Debt Paydown		(225)
<b>Total Debt Reduction</b>		<b>(435)</b>
<b>Net Capital Available Remaining</b>		<b>535</b>
Implied Year-End Cash Balance		635
Management Liquidity Target		\$1,000
Revolver Capacity		\$1,678

Source: Company filings

### Debt and equity de-linked?

The debt remains largely intact through the credit crisis in the energy sector of late, largely trading near par, preventing shares from being bought back at a discount. We continue to expect most debt paydown to be oriented towards 2H16 regardless given timing of cash flow.

**Figure 80: CPN – Bond Yields**



Source: FactSet

## Debt trading at a premium

Looking at the notes that have quoted prices, the secured debt is trading at a premium to its par value while the senior notes have recovered to trade near par as well.

Figure 81: Calpine Debt Profile –Current Interest, MtM, and Maturities

As of 9/30/15 (Except Current Yield)	Maturity (yr)	Book Yield	Current Yield	2015	2016	2017	2018	2019	2020+	Current Price
<b>Calpine Corp.</b>										
Senior Notes		5.38%	5.42%						1,250	99
Senior Notes		5.50%	5.58%						650	99
Senior Notes		5.75%	5.81%						1,550	99
First Lien Term Loan		4.30%	5.91%				-			
First Lien Term Loan		4.40%	5.91%					810		
First Lien Term Loan		4.30%	5.91%		4				383	
First Lien Term Loan		3.75%	5.91%		16	16	16	16	1,524	
First Lien Secured Notes		6.00%	5.67%						745	106
First Lien Secured Notes		7.88%	7.39%						693	107
First Lien Secured Notes		5.88%	5.58%						490	105
<b>Total Calpine Corp.</b>		<b>8,162</b>		-	20	16	16	826	7,285	
<b>Total Maturities</b>		<b>8,162</b>		-	20	16	16	826	7,285	
Book Interest Expense (Consolidated)		\$432		Book Interest Expense (Ex-GenCo)				\$432		
MtM Interest Expense (Consolidated)		\$479		MtM Interest Expense (Ex-GenCo)				\$479		
Delta (%)		-10%		Delta (%)				-10%		
2018E EBITDA (UBSe)		\$2,236		2018E EBITDA (UBSe)				\$2,236		
Delta (%)		-2%		Delta (%)				-2%		
2018E FCF (UBSe)		\$1,044		2018E FCF (UBSe)				\$1,044		
Delta (%)		-5%		Delta (%)				-5%		

Source: Company reports, FactSet, UBS estimates

## Latest EBITDA estimates

We include our latest segment level EBITDA estimates for the company, continuing to show a nice step-up in our 2017+ EBITDA estimates principally on the back of higher capacity prices across PJM and New England as well as from new assets reaching in-service.

Figure 82: CPN estimates

Calpine Adj. EBITDA UBSe	2015	2016	2017	2018	2019	2020
West	745	610	607	576	510	499
Texas	411	438	551	542	494	465
Southeast	-	50	47	46	46	45
North	742	631	806	868	885	888
Other	30	33	35	35	36	37
Corporate Allocation	48	153	167	170	172	175
<b>Total EBITDA</b>	<b>1,976</b>	<b>1,915</b>	<b>2,213</b>	<b>2,237</b>	<b>2,142</b>	<b>2,108</b>
Guidance	<b>1965-2000</b>	<b>1800-1950</b>				
Street Consensus	1,991	1,918	2,059			
UBS Previous	1,976	1,894	2,177	2,236	2,228	2,198
EBITDA Change %	0.0%	-1.1%	-1.7%	0.0%	4.0%	4.3%
EBITDA Change \$	\$0	\$21	\$37	\$1	-\$85	-\$90

Source: Company reports, UBS estimates

## Valuation: Maintain price target at \$17/sh

We are maintaining our price target at \$17/sh with little change in our 2017 EBITDA estimates. We continue to see shares as trading principally as a function of the credit cycle in high-yield energy given its higher leverage.

**Figure 83: Calpine SOP Valuation: Sticking with our \$17 PT on refresh**

All figures in US \$ million except per share data							
	2017E EBITDAR	EV/EBITDA Multiple			Enterprise Value		
		Low	Base	High	Low	Base	High
West	607	5.0x	6.0x	8.0x	\$3,036	\$3,643	\$4,857
Texas	551	6.0x	7.0x	8.0x	3,308	3,859	4,411
Southeast (Remaining)	47	6.0x	7.0x	8.0x	282	330	377
North	806	6.0x	7.0x	9.0x	4,835	5,641	7,253
Other	35	6.0x	7.0x	8.0x	207	242	277
Hedge Impact (Adj. for Steam, etc.)	(43)	6.0x	7.0x	8.0x	(260)	(303)	(346)
Champion Energy	50	4.0x	5.0x	6.0x	200	250	300
Adj. for Commodity Margin to EBITDA	117	6.0x	7.0x	8.0x	704	822	939
<b>Total / Implied</b>	<b>2,170</b>	<b>5.7x</b>	<b>6.7x</b>	<b>8.3x</b>	<b>\$12,313</b>	<b>\$14,483</b>	<b>\$18,067</b>
Subtract: Net Debt						(10,734)	
Subtract: Operating Leases						(198)	
Add: NPV of NOLs						1,171	
Add: Hedge Value						43	
Add in Further Plant-Level Value	MWs	\$/kW					
Remaining Southeast Portfolio:		Low	Base	High			
Auburndale Peaking Energy Center (FL)	117	\$100	\$200	\$300	\$12	\$23	\$35
Osprey Energy Center (FL) - Duke Sale	599	\$277	\$277	\$277	166	166	166
Pine Bluff Energy Center (AR)	215	\$150	\$250	\$350	32	54	75
Morgan Energy Center (AL)	807	\$150	\$250	\$350	121	202	282
<b>Total / Implied</b>	<b>1,738</b>				<b>\$337</b>	<b>\$445</b>	<b>\$559</b>
Subtracting out EV/EBITDA-based Southeast Portfolio					(282)	(330)	(377)
True 'Merchant' West Portfolio:							
Metcalf (CA)	605	\$150	\$250	\$350	91	151	212
Hermiston (OR)	635	\$150	\$250	\$350	95	159	222
South Point (AZ)	530	\$150	\$250	\$350	80	133	186
<b>Total</b>	<b>1,770</b>				<b>\$266</b>	<b>\$443</b>	<b>\$620</b>
Subtracting out Associated EBITDA	36				(180)	(216)	(288)
<b>NPV of Equity</b>					<b>\$2,686</b>	<b>\$5,107</b>	<b>\$8,819</b>
Projected Number of Shares Outstanding (2017E)					294	294	294
<b>Equity value per share</b>					<b>\$9.00</b>	<b>\$17.00</b>	<b>\$30.00</b>
Implied \$/KW					472	555	692
FCF (pre-growth) for 2017						1,034	
<b>Implied FCF Yield on Price Target</b>						<b>20.2%</b>	

Source: Company reports, UBS estimates

## Latest FCF Outlook

We include our latest FCF projections, with our 2016 estimate sitting squarely near the midpoint of the range through our latest MtM. The question remains just how much debt will be paid down relative to shares bought back, particularly following management's latest commentary suggesting it should have been clearer on debt paydown ambitions through the latest downturn

**Figure 84: Our latest FCF projections**

Calpine FCF Analysis (UBSe)	2014	2015E	2016E	2017E	2018E	2019E
UBS FCF Est. (\$Mn)	830	671	765	1,034	1,044	937
~\$250 Mn uplift ex-Hedges from 2016-2018						
Management FCF Guidance (\$Mn)	800-850	825-860	710-860			
FCF per Share (using Avg)	2.03	1.73	2.19	3.30	3.80	3.97
Management FCF/Share Guidance	1.85 - \$2.10	\$2.25-2.35	\$2.00-2.40			
FCF Growth (YoY)	32%	-15%	27%	51%	15%	4%
CAGR off 2011 of \$1.01 FCF/shr	26.1%	14.5%	16.8%	21.8%	20.9%	18.7%
<b>FCF Yield</b>	<b>18.8%</b>	<b>15.2%</b>	<b>17.4%</b>	<b>23.5%</b>	<b>23.7%</b>	<b>21.3%</b>
Turbine Upgrade	(20)	0	0	0	0	0
Deer Park, TX (CT Addition)	(34)	0	0	0	0	0
Channel, TX (CT Addition)	(34)	0	0	0	0	0
Garrison, DE (New PJM CCGT)	(48)	0	0	0	0	0
York CCGT (New PJM CCGT)	0	(133)	(285)	(265)	0	0
Other Growth (Mankato, etc)		(223)	0			
<b>Growth Capex</b>	<b>(136)</b>	<b>(355)</b>	<b>(285)</b>	<b>(265)</b>	<b>0</b>	<b>0</b>
Growth & Acquisition Financing		(240)	(500)	Granite Ridge		
Projected Debt Amort/Sweeps	(320)	(460)	(435)	(200)	(200)	(210)
<b>Remaining FCF</b>	<b>374</b>	<b>(161)</b>	<b>(455)</b>	<b>569</b>	<b>845</b>	<b>727</b>
Asset Sales	1,573	0	0	0	0	0
Starting Cash	941	717	906	906	906	906
Ending Cash	717	906	906	906	906	906
<b>Δ in Cash Balance</b>	<b>(224)</b>	<b>189</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>(0)</b>
<b>Deployable for Growth/Share Repo</b>	<b>2,171</b>	<b>(350)</b>	<b>(455)</b>	<b>569</b>	<b>845</b>	<b>727</b>
Share Repurchase Placeholder	(1,100)	(529)	(425)	(500)	(500)	(500)
Projected Shares YE O/S	409	365	332	294	255	217

Source: Company reports, UBS estimates

*For more detail on CPN, please see our other recent reports:*

[2/16/2016: Preparing for a Gradual Debt Paydown](#)

[2/12/2016: Pausing on Buybacks](#)

[11/2/2015: Reaching the Trough](#)

# CMS Energy Corporation

Investor expectations for Michigan legislation have declined with the passage of time in the session and now there are only ~10 weeks of full session remaining before the summer recess (mid-June). Management recently lifted the long-term EPS CAGR 100bp to 6-8% without the legislation but shares have largely tracked the group which we attribute to high investor expectations for organic growth. As the probability of legislation declines, shares could prove weak in the near term.

We forecast CMS reporting adjusted 1Q16 EPS of **\$0.61**, sharply below consensus (\$0.83) and representing a modest step-down compared with the prior year (\$0.73). CMS significantly benefited from above-average degree days in 1Q15 but that dynamic reversed in early 2016. New rates for 2016 will offset much of the weather impact but the weak start to the year will likely drive CMS to implement 'lean' O&M efforts. Although we expect a weak first quarter, the -\$0.14 1Q15 weather comparison reverses during the year and FY15 weather largely nets out during the year. Furthermore if the balance of year weather does not improve, management has commented that there is flexibility on spending for maintenance work, tree trimming, donations, etc.

CMS has among the largest negative weather impacts but consensus still expects YoY growth

Figure 85: CMS 1Q16E Earnings Walk

CMS Energy 1Q16 Earnings Walk		EPS
<b>1Q15A Adjusted EPS</b>		<b>\$0.73</b>
<b>Utilities YoY</b>		
Weather		
Weather vs Normal in 1Q15 +15% Degree Days		(0.14)
Weather vs Normal in 1Q16 -12% Degree Days		(0.10)
Revenues		
2015 Electric Case: \$165Mn December 2015		0.09
2015 Gas Case: \$45Mn January 2016		0.04
<u>2016</u> Electric Case: \$225Mn w./ \$38Mn for '17		0.00
O&M		
Lower O&M (further cuts to offset weather)		0.07
Higher Benefit Costs: Mortality tables & discount rates		(0.02)
DIG Maintenance		0.00
Interest Expense		0.00
Investment Costs: D&A, Property Taxes, etc.		(0.06)
<b>Enterprise YoY</b>		<b>0.00</b>
<b>Interest and Other YoY</b>		
Dilution		(0.00)
<b>1Q16E Adjusted EPS</b>		<b>\$0.61</b>
<b>1Q16 Consensus</b>		<b>\$0.83</b>
<b>2016 UBSe EPS</b>		<b>\$2.02</b>
<b>2016 Consensus</b>		<b>\$2.02</b>
<b>2016 Guidance</b>		<b>\$1.99-\$2.02</b>

Source: Company filings, FactSet, UBS estimates

*For additional context, please refer links to relevant recent reports below:*

[2/10/16 Leaning Into Their Bonus](#)

[10/30/15 Delivering on Plan](#)

[10/26/15 Tapping the Brakes](#)

[10/26/15 Positioning the Quality Premium for Regulated Utilities](#)

[7/24/15 Gain with No Pain](#)

[4/24/15 Holding the Line on 7%](#)

[4/10/15 Making up for Lost Time](#)

[1/30/15 Under-Promising and Over-Delivering in Michigan](#)

## What are the pivotal questions for CMS?

- **Few updates on Michigan energy legislation during recess:** The legislature returned from Easter recess on April 12<sup>th</sup> with approximately ten weeks left before the summer break. Currently the Senate Energy and Technology Committee has not finalized a bill but Chair Senator Mike Nofs (R) is expected to introduce a substitute bill and he commented on April 11<sup>th</sup> that the prospects of energy legislation is “not dead”. Based upon media reports there continues to be multiple aspects of the potential legislation that are debated such as the ultimate terms for consumer choice/switching’ and renewables mandate/goal. We continue to highlight that this year is an election year in Michigan so based on historical precedents it is unlikely that comprehensive legislation will be reviewed in the period after June. Management indicated on the 4Q15 earnings call that it expected legislation to be passed by 1H16 but we expect management to significantly temper expectations on its April 28<sup>th</sup> call.

- **Requesting multi-year electric rates in latest case:** CMS filed its latest electric ratecase on March 1<sup>st</sup> \$225Mn over a three year period (2017-2019) based on a 10.7% ROE. The majority of the request is to recover for capital investments (\$161Mn, 72%) and \$17Mn relates to lower peak customer delivery sales. The delta between the 10.7% ROE request and the 10.3% authorized is \$25Mn. (Docket C-U-17990)

In the pending gas case filed in July 2015 the Michigan PSC Staff recommended a \$19Mn rate increase with a 10% ROE vs. CMS’s original request of \$85Mn with a 10.7% ROE. In this case the ROE delta explains \$19Mn of the difference between the Company and Staff while incentive Compensation (\$10Mn) and other items bridge the rest of the gap. Additionally the Staff did not recommend CMS’ investment recovery rider but seemed to not oppose the implementation of a revenue decoupling feature. (Docket C-U-17882)

The protracted process in crafting the bill could result in a faster review process if actually introduced

CMS implemented a \$60Mn rate increase in mid-January 2016

## EPS estimates unchanged

We are maintaining our EPS estimates through 2019 are unchanged and remain largely in line with consensus. As mentioned 1Q16 weather creates a headwind but management has conservatively established a 'reinvestment' contingency. With -\$0.31 of "investment costs" in the guidance for 2016, we note that a portion of this is opportunistic (some maintenance work, tree trimming, donations, etc.) that could be reduced if needed or increased if possible. Bottom line is that CMS seems highly confident in its 6%-8% long-term EPS growth rate. For example CMS raised its 2016E guidance on February 4<sup>th</sup> when it reported FY15 earnings which incorporated preliminary weather data for the year.

**We are maintaining our estimates at 7% annual earnings growth (midpoint of the recently updated 2017+ 6-8% target) through 2017**

**Figure 86: CMS EPS Estimates (2014A-2019E)**

<b>CMS EPS Breakdown</b>	<b>2014A</b>	<b>2015E</b>	<b>2016E</b>	<b>2017E</b>	<b>2018E</b>	<b>2019E</b>
<b>Consumers Electric</b>	\$1.40	\$1.43	\$1.41	\$1.50	\$1.59	\$1.68
<b>Consumers Gas</b>	\$0.65	\$0.69	\$0.68	\$0.72	\$0.77	\$0.81
<b>DIG Cogen Merchant Unit</b>	\$0.02	\$0.04	\$0.06	\$0.05	\$0.03	\$0.02
<b>EnerBank</b>	\$0.07	\$0.07	\$0.08	\$0.09	\$0.09	\$0.10
<b>Parent Drag and Other</b>	(\$0.37)	(\$0.33)	(\$0.22)	(\$0.20)	(\$0.17)	(\$0.14)
<b>Total CMS EPS UBSe</b>	<b>\$1.77</b>	<b>\$1.89</b>	<b>\$2.02</b>	<b>\$2.16</b>	<b>\$2.31</b>	<b>\$2.46</b>
<b>UBSe Prior</b>	<b>\$1.77</b>	<b>\$1.89</b>	<b>\$2.02</b>	<b>\$2.16</b>	<b>\$2.31</b>	<b>\$2.46</b>
<b>UBSe EPS CAGR 2016-2019</b>						7.1%
<b>Management Guidance - EPS Growth 2017+ (%)</b>			\$1.99-\$2.02			6%-8%
<b>Total Guidance EPS</b>						
<b>Street Consensus EPS</b>	<b>\$1.77</b>	<b>\$1.89</b>	<b>\$2.02</b>	<b>\$2.17</b>	<b>\$2.33</b>	<b>\$2.47</b>

Source: Company filings, FactSet, UBS estimates

## Valuation: Maintain \$41 price target

We are rolling forward our valuation to 2018E from 2017E previously continuing to use a sum-of-the-parts methodology. Additionally we have lowered the probability we apply to incremental spending opportunities in Michigan for the proposed legislative reforms to 50% from 75% as the legislative session window slowly closes. Even if there are no energy reforms in 2016, we still ultimately expect this to occur in the future based upon the challenges in the current set of standards. Investors' expectations for legislation have declined but we still see reforms baked into shares at present.

**What's changed in our valuation?**  
**+\$2/sh Increase in Peer Multiple**  
**-\$2/sh Decreased Probability of Incremental Opportunities**

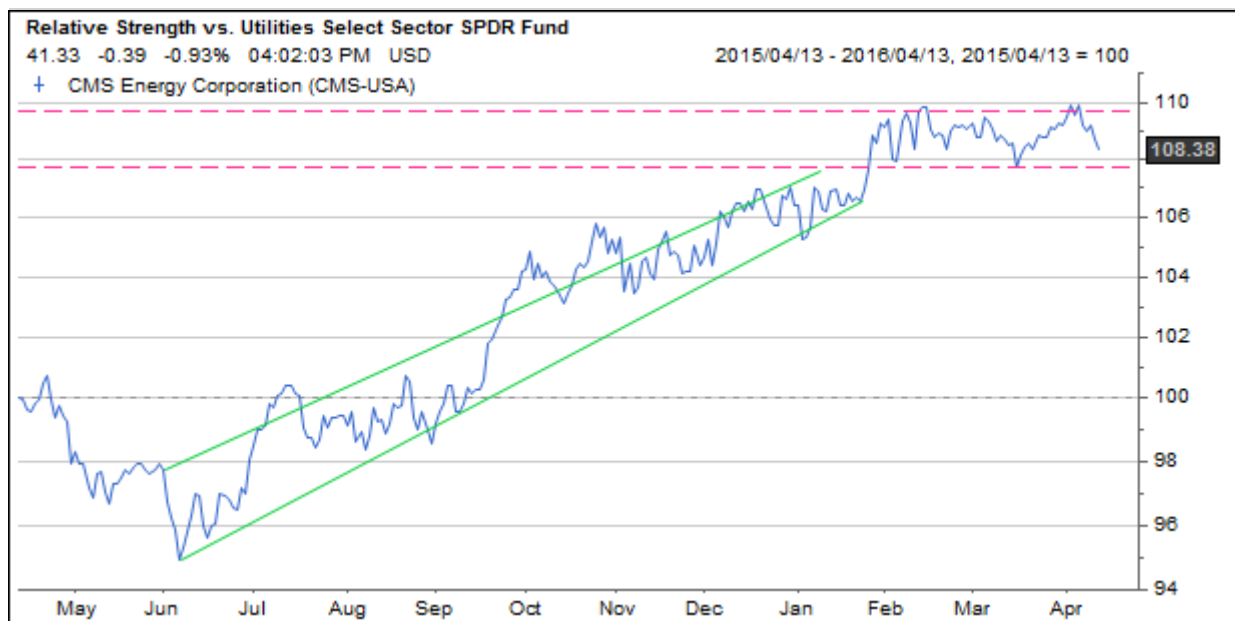
Figure 87: Updated CMS Energy Sum-of-the-Parts Valuation

Business Segment	Valuation Metric	2018	Low Case		(\$ MM)	Base Case		(\$ MM)	High Case		(\$ MM)	
			Valuation Multiple			Base Valuation Multiple			Valuation Multiple			
Regulated Entities												
						Peer Multiple	Prem/(Disc) to Peer	Base Multiple				
Consumers Electric - Base Capex	P/E	\$1.51	15.5x		\$6,493	16.5x	0.5x	17.0x		\$7,121	\$7,540	
Consumers Gas	P/E	\$0.77	15.5x		\$3,301	17.5x	0.0x	17.5x		\$3,727	\$3,940	
Incremental Opportunities												
Elimination of ROA	P/E	\$0.11	15.5x	Probability 0%	\$0		0.0x	16.5x	Probability 50%	\$248	Probability 100%	\$526
Renewables - Wind		\$0.07	15.5x	0%	\$0			16.5x	50%	\$168	100%	\$356
Palisades PPA Expiration		\$0.09	15.5x	0%	\$0			16.5x	50%	\$203	100%	\$431
MCV PPA Expiration		\$0.11	15.5x	0%	\$0			16.5x	50%	\$243	100%	\$515
Regulated, Equity Value (\$Mn)					\$9,794				\$11,711	\$13,310		
Regulated, Equity Value (\$/sh)					\$35.19				\$42.08	\$47.82		
Unregulated and Parent Businesses												
EnerBank	P/E	\$0.09	11.0x		\$278		12.0x		\$304	13.0x	\$329	
Dearborn Industrial Generation (DIG)	\$kW	770	278		\$214		328		\$252	378	\$291	
Parent & Other	P/E	(\$0.17)	18.0x		(\$850)		17.0x		(\$803)	16.0x	(\$756)	
Unregulated, Equity Drag (\$Mn)					(\$358)				(\$247)	(\$136)		
Unregulated, Equity Drag (\$/Sh)					(\$1.28)				(\$0.89)	(\$0.49)		
CMS Equity Value					\$9,437				\$11,465	\$13,175		
Fully Diluted Outstanding Shares (2017E)					278				278	278		
CMS Equity Value per Share					\$34.00				\$41.00	\$47.00		

Source: Company filings, FactSet, UBS estimates

For example as shown below CMS has 'only' tracked the group since late January after consistent outperformance from June 2015 onward.

Figure 88: CMS Relative Performance



Source: FactSet

# Consolidated Edison

Shares continue to trade an ~8% P/E premium to utility peers, near a multi-year high, and versus a consistent discount during 2013-2014 (and most of 2015). We understand that shares typically rally in a risk-off market but we continue to believe shares deserve a fundamental 5% discount given the lack of load growth, below-average earned ROEs, and lingering uncertainty around the March 2012 Harlem blast. Based on conversations with investors, most are not pricing in any liabilities for the Harlem explosion (a contrast from Sempra and its gas leak which has been a catalyst in its underperformance). However, the below-average organic growth opportunities in the utility footprint continue to keep us less disposed to favor the name.

We expect ED to report 1Q16 adjusted EPS of **\$1.14** down from a strong 1Q15 and below consensus (\$1.22). Although ED benefits from weather normalization at most businesses, well above-normal steam revenue last year (~\$0.08) and lower benefit costs in created a robust 1Q15. Although ED benefits from new rates in 2016 its allowed ROE declines to 9% from 9.2% which will reduce the ability to earn in the sharing band like it did in 2015.

A steamy 2015 winter was followed by a particularly mild one

Figure 89: ED 1Q16E Earnings Walk

ConEd 1Q16 Earnings Walk	EPS
<b>1Q15A Adjusted EPS</b>	<b>\$1.25</b>
<b>Con Edison of New York (CEConY)</b>	
Changes in Rate Plans	0.07
Impact of Steam in 1Q15	(0.08)
Impact of Steam in 1Q16	(0.04)
O&M Inflation and Normalization of 1Q15	(0.03)
D&A and Property Taxes	(0.04)
Net Interest Expense	(0.02)
Oil-to-Gas Conversion	0.01
Other	-
<b>Orange &amp; Rockland Electric and Gas (O&amp;R)</b>	
Changes in Rate Plans	0.02
O&M	(0.01)
Other	(0.00)
<b>Competitive Energy Businesses</b>	
ConEd Solutions (CES) Ex-MtM	0.02
ConEd Development (CED) Ex-LILO	0.01
ConEd Energy (CEE)	-
<b>Parent &amp; Other</b>	<b>(0.01)</b>
<b>1Q16E Adjusted EPS</b>	<b>\$1.14</b>
<b>1Q16 Consensus</b>	<b>\$1.22</b>
<b>2016 UBSe EPS</b>	<b>\$4.00</b>
<b>2016 Consensus</b>	<b>\$4.00</b>
<b>2016 Guidance</b>	<b>\$3.85-\$4.05</b>

Source: Company filings, FactSet, UBS estimates

*For additional context, please refer links to relevant recent reports below:*

[2/25/16 When Cash Flow and Earnings Don't Mix: Solar](#)

[2/19/16 More Equity Please?](#)

[1/26/16: What Lies Behind the Defensive Veneer](#)

[10/9/15 Fitting Renewables Into the Mix](#)

[8/13/15 A Green Lining in the Clouds](#)

[5/05/15 Consolidating Edison](#)

[2/24/15 ROE Risk Remains in Focus](#)

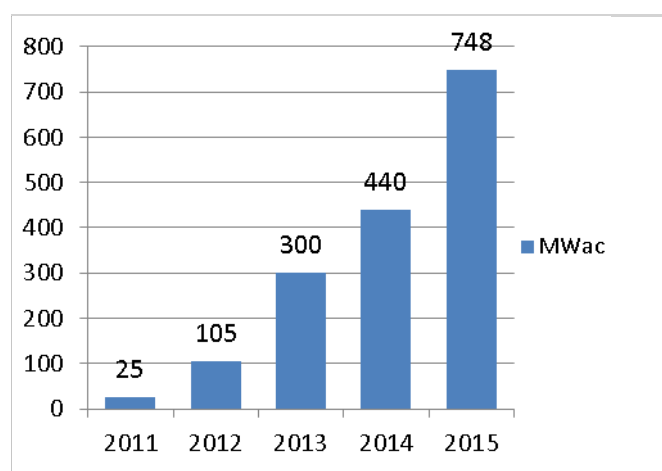
## What are the pivotal questions for ED?

### How large can the Competitive businesses grow?

- **Little tax appetite = less interest in renewables:** We note Con Edison was quite clear in its decision to scale back future investments in renewables amidst relatively limited projected tax appetite going forward. In 2015 ED had an -\$86Mn current federal tax expenses with \$569Mn deferred. While we estimate that ED's returns on renewables including tax credits are a healthy 14% IRR, the economics without such immediate return via tax credits is substantially reduced [[details here](#)]. We suspect this could be the trend elsewhere in the sector, even for ratebase projects, which ultimately depend on the utilities' ability to absorb these credits.

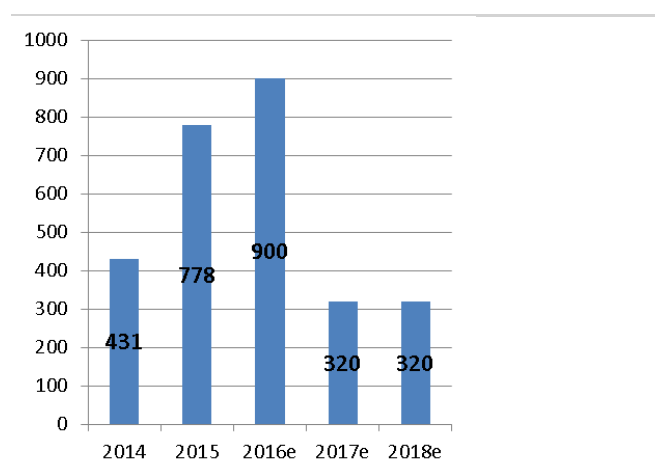
ED received a \$224Mn refund (\$128Mn at CECONY) in March 2015 following the extension of bonus depreciation

Figure 90: ConEd Renewable Portfolio



Source: Company filings

Figure 91: CED Historic and Projected Investments



Source: Company filings

- **ConEd renewables growth still a debated topic:** Management continues to internally debate the pace and magnitude of its renewables development business as it seeks to balance the challenges inherent in a cash/IRR business inside of a regulated utility which is predominately valued on a P/E basis. Management does not believe the potential for debt imputing from the parent company down to the utilities will be a 'red flag' for the PSC Staff but ED continues to think broadly about how much it wants to grow the subsidiary; however, we see this is a risk to future scaling the business (effectively a 'handicap' on the economics).

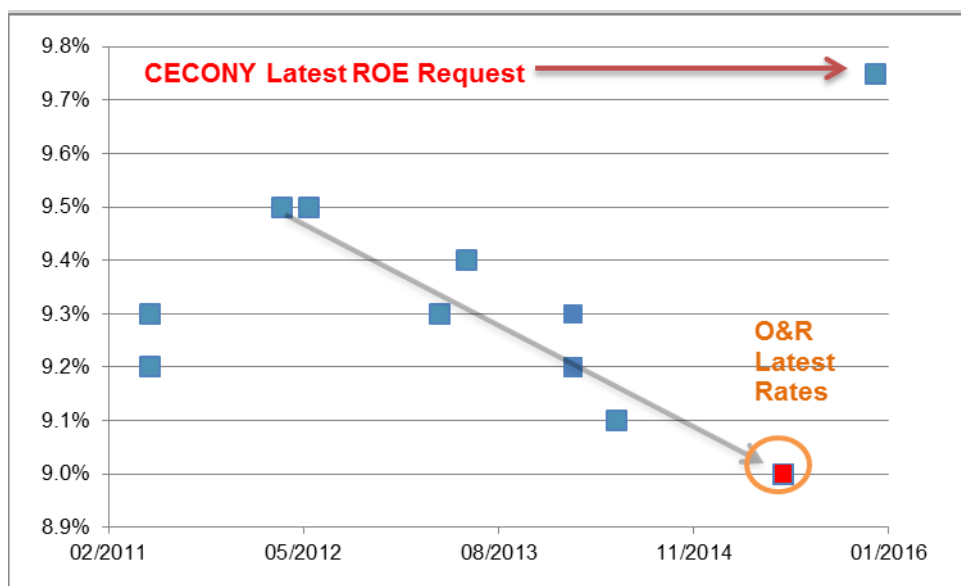
ConEd Development has generated \$15-\$30Mn of earnings the past few years highlighting the discrepancy between EPS and IRR

### Where is the ROE trending and what incremental capex opportunities are available at the utilities?

- **We see the ROE as a continued headwind:** Based upon the NY PSC Staff's formula we see the ROE mark-to-market at ~8.3%, essentially flat YoY (seeing downside pressure on the 9% current settled in the last case for electric and 9.3% for gas & steam). We emphasize keeping its authorized ROE at 9% would appear a *good* outcome given the wider pressures using the formulaic approach employed by the NY PSC amidst recent low interest rates and high utility valuations; the methodology grabs both metrics, suggesting a mid-to-low 8% ROE.

Based upon the NY PSC Staff's formula we see the ROE mark-to-market at ~8.3%, essentially flat YoY (seeing downside pressure on the 9% current settled in the last case for electric and 9.3% for gas & steam)

Figure 92: Where will the ROE land? We see risk to the downside



Source: Company filings, SNL Energy

Further details on our estimate of the NY PSC ROE mark-to-market analysis are available from our January report [What Lies Behind the Defensive Veneer](#)

- Can 2016's 9.6% ROE be repeated?** We include our latest expectations for earned ROEs by segment below vs. historical levels as well as projected ratebase. We note the earned 9.6% ROE in 2015 reflects the maximum CECONY can earn, with incremental EPS above this level accruing back to customers via a refund. The question remains to what extent the same factors enabling CECONY to earn 60bp above 9% will recur in 2016 projections, given continued benefits of cost cuts. 2016 was seemingly aided by reduced O&M on the electric side with fewer summer outages due to cooler weather on average. That said, 2017 should recapture much of these savings back into customer rates.

All four ratecase decisions in 2015 had 9% ROEs (Central Hudson Gas & Electric, CECONY Electric, O&R Gas, and O&R Electric), down from 9.1-9.3% in 2014

Figure 93: ED Projected Earned ROEs for CECONY

Regulated Metrics	CECONY Historical and Projected ROEs						
	2011A	2012A	2013A	2014E	2015E	2016E	2017E
Estimated Rate Base (period end)	20,260	20,624	21,143	22,400	23,600	25,000	25,750
Estimated Rate Base Growth	3.91%	1.80%	2.52%	5.95%	5.36%	5.93%	3.00%
Estimated Rate Base (average)	19,879	20,442	20,884	22,355	23,000	24,300	25,375
Equity Percentage	52.0%	54.0%	50.5%	50.9%	50.9%	50.9%	50.9%
Allowed Equity Ratio			48.0%	48.0%	48.0%	48.0%	48.0%
Effective Equity Ratio				50.0%	50.0%	50.0%	50.0%
ROE Earned - Regulated Basis	9.70%	10.18%	9.34%	9.10%	9.60%	8.82%	8.79%
Electric				9.20%	9.80%		
Gas				7.50%	8.20%		
ROE Earned - SEC Basis	9.80%	9.81%	9.61%				
Authorized ROE	10.00%	10.00%	10.00%	9.22%	9.22%	9.00%	9.00%
Model Earned ROE (Avg. GAAP Equity)	9.57%	9.76%	9.51%	9.55%	9.45%	9.03%	9.09%
ROE Variances						-0.5%	-0.5%
Regulated v SEC Basis	-0.10%	0.37%	-0.27%				
SEC v Allowed Basis	-0.20%	-0.19%	-0.39%				

Source: Company filings, UBS estimates

- **What can we learn from Avangrid about NY earning expectations?** In our March meeting with Avangrid management the company stated it intends to earn at least the authorized rates of returns, pointing towards sharing bands in both New York and Connecticut. In the recent NY ratecase settlement AGR's utility NYSEG is allowed to earn at a 50% equity ratio for sharing calculation purposes which initially kick-in at a 9.5% ROE in year one. The sharing thresholds increase by 15bp and 10bp in years two and three, respectively, acting as a partial hedge against potential rising interest rates. Between the sharing mechanism, forward test years, and various trackers, management expressed confidence on utility earnings prospects. Synergies as part of the Iberdrola/UIL merger are still being studied and could provide further upside in management's view.
- **Detailing how capital spending forecasts evolved:** We include the latest and previous forecasts below. The transmission below is principally the MVP gas pipeline investment, whereas the competitive businesses are principally the solar investments. Recall management amortizes ITC over a period of time rather than recognizing the benefits all in the year when the asset begins commercial operations (more conservative approach).

Based upon the equity ratio 'flex' and sharing bands there is an opportunity to earn above the allowed ROE in NY

We see management as busily adding other investment opportunities to its core utility efforts, recently adding a stake in the MVP pipeline, a further TX solar project for \$375 Mn, and approval of a \$1.3 Bn smart meter AMI program from the NYPSC (this capex remains reflected already in management's forward looking estimates)

Figure 94: 2015 10K ConEd Capex Disclosures

Capital Expenditures	2013	2014	2015	2016	2017	2018
ConEd NY	\$2,135	\$2,132	\$2,435	\$2,865	\$2,999	\$2,991
O&R	135	142	160	188	185	184
<b>Total Regulated</b>	<b>2,270</b>	<b>2,274</b>	<b>2,595</b>	<b>3,053</b>	<b>3,184</b>	<b>3,175</b>
Coned Transmission				115	171	179
Competitive Businesses	378	447	823	985	360	360
<b>ConEd Total Capex</b>	<b>\$2,648</b>	<b>\$2,721</b>	<b>\$3,418</b>	<b>\$4,153</b>	<b>\$3,715</b>	<b>\$3,714</b>

Source: Company filings

The latest forecast is significantly higher than the prior forecast, particularly at the utility. We remind investors that the EPS uplift from the solar projects appears to be minimal according to management's guidance due to the spreading of ITCs mentioned above.

Figure 95: 2014 10K ConEd Capex Disclosures

Capital Expenditures	2013	2014	2015	2016	2017	2018
ConEd NY	\$2,135	\$2,132	\$2,375	\$2,661	\$2,694	\$1,750
O&R	135	142	162	182	177	150
<b>Total Regulated</b>	<b>2,270</b>	<b>2,274</b>	<b>2,537</b>	<b>2,843</b>	<b>2,871</b>	<b>1,900</b>
Competitive Businesses	378	447	835	985	374	374
<b>ConEd Total Capex</b>	<b>\$2,648</b>	<b>\$2,721</b>	<b>\$3,372</b>	<b>\$3,828</b>	<b>\$3,245</b>	<b>\$2,274</b>

Source: Company filings

- **REV reforms appear unlikely to drive big opportunity yet.** ED management has emphasized that it does not expect to be able to invest directly in any distributed investment opportunities. Rather, the key question emerging in the latest Track II proceedings around REV implementation is to what extent will ConEd be able to invest in the corresponding implementation to 'enable' this distributed platform (ex. T&D, smart meters, etc.). While financial estimates are available yet, this could be quite a material figure given the scope of REV ambitions. Timing on REV related spending still remains unclear given the glacial pace of the reform process thus far and risk of personnel turnover at the NYPSC.

With REV reforms seemingly predicated in part on digital communication embedded within meters, we see firm prospects for deployment of the full \$1.5Bn contemplated electric & gas capital from 2016-2022. Much of this spend is already reflected in the existing capital budget but could be accelerated slightly

## What is the latest with New York transmission opportunities?

*Avangrid is a partner in the 2014 NY TransCo joint venture with ConEd and National Grid. The partnership was formed to collectively bid on transmission opportunities within the state.*

- **We emphasize among the RTOs seeing the most activity of late, it's actually New York:** Not only is the state focused on two concurrent FERC Order 1000 solicitations, but we see a wider effort underway to encourage investment via streamlining of the Article X process. While feedback from the meetings did not appear particularly encouraging for those pursuing development activity outside of the current Order 1000 processes (eg- PPL's Compass project), we note the clear recognition of citing issues as a priority to address in the state. We continue to await AGR's own proposal in coming weeks, seemingly with 1Q results as management had anticipated a late April update. The question is how such an expansion in NY activities will impact ED?
- **Connect New York: Offering a DC solution:** AGR has worked on its DC proposal for multiple years and indicated that projects that run smoothly can take approximately seven years from conception to completion. Connect New York is an 130-200-mile underground DC project from Utica (Zone E) towards New York City (Zone J) along the freeway across the two main congestion points which would support Adirondack wind. While the Energy Highway has thus far focused primarily on AC transmission projects, AGR's DC proposal utilizing existing right-of-ways but would require expensive convertors on both ends. Preliminary details from Iberdrola in ~2012 are available [here](#); however, the scope of the project has likely evolved over time. Responses are due April 28<sup>th</sup> and since management has been working on the project for many years it believes it could act quickly if selected. What will TransCo's propose?

Separately in NY AGR is collaborating in NY with New York Power Authority (NYPA) on a project to help reduce congestion for the Niagara hydro. With merchant nuclear assets in the state struggling with low power prices Avangrid management believes it can either help improve prices by reducing congestion or help reduce reliability issues if the plants ultimately retire. For example the Ginna Retirement Transmission Alternative ~\$140Mn project from 2015-2017 will support local reliability if the plant closes.

- **How to meet the future New York renewable goals? Imports:** Amidst this focus on transmission, it appears New York state is likely to turn to imports from adjacent regions to source its renewable requirements. We would not doubt an effort to procure additional North-South capacity to interconnect ultimately back into the Canadian system. While Blackstone has proposed its longstanding TDI project, we see a wider interest in developing such capacity to expand hydro imports. We think the 50% RPS will be established to include external hydro as qualifying. This will complement still nascent efforts to expand stymied wind development efforts in upstate/Western New York, principally along the lakes.

Avangrid management has very highly discounted the DC project in its capital plan and only briefly discussed it at its Analyst Day (no slides on it)

Bottom line, New York appears to mirror New England in many respects

## Will ED sell its retail business?

- **Hitting a snare on the sell-down of the retail biz?:** Based upon our recent conversations with management the company remains committed to the sale of this business – despite some apparent issues in executing. We note interest in retail continues to grow, suggesting some modestly improved prospects. We note the outsized EPS in 2015 could help boost a sale price. We note recent transactions remains in the ~5x EBITDA range, dilutive to ED assuming continued positive EPS; that said, the limited contribution and volatility introduced into its earnings profile does not fit with the contracted and consistent EPS desired by ConEd investors.

A number of competitive generators have discussed a desire to increase their retail presence to better hedge their volume following reduced liquidity in the commodity markets

## EPS Estimates

Below we show our EPS estimates which are essentially unchanged.

Figure 96: Updated ED EPS Estimates

Consolidated Edison EPS Ests.	2014	2015	2016E	2017E	2018E
Consolidated Edison of New York	\$3.61	\$3.77	\$3.60	\$3.71	\$3.87
CECONY ROE (UBSe)	9.1%	9.6%	8.8%	8.8%	9.0%
Orange & Rockland (O&R)	\$0.20	\$0.15	\$0.22	\$0.22	\$0.22
Competitive Businesses:					
Con Ed Solutions (Retail)	(\$0.00)	\$0.07	\$0.02	\$0.01	\$0.00
Con Ed Energy (Wholesale)	\$0.05	\$0.03	\$0.02	\$0.00	\$0.00
Con Ed Development (Solar)	\$0.05	\$0.12	\$0.16	\$0.19	\$0.22
Parent and Other	(\$0.02)	(\$0.08)	(\$0.03)	(\$0.06)	(\$0.13)
<b>Consolidated (diluted shares)</b>	<b>\$3.89</b>	<b>\$4.06</b>	<b>\$4.00</b>	<b>\$4.07</b>	<b>\$4.19</b>
% Growth		4%	-2%	2%	3%
Prior estimates		\$4.05	\$4.00	\$4.07	\$4.19
<b>Guidance</b>		<b>\$3.90-\$4.05</b>	<b>\$3.85-\$4.05</b>		
Consensus	\$3.89	\$4.08	\$4.00	\$4.15	\$4.31

Source: Company filings, FactSet, UBS estimates

## Valuation: Increase price target to \$66

Our valuation remains based on 2018 P/E methodology. We continue to apply a 5% discount to shares *given the lack of load growth, below-average earned ROEs, and lingering uncertainty around the March 2012 Harlem blast. The increase in our price target is driven entirely by the 1.0x-turn improvement in the regulated peer multiple.*

Figure 97: Consolidated Edison Valuation

Consolidated Edison Valuation			
Regulated 2018 P/E Multiple	16.5x		
	Downside	Base Case	Upside
2018 EPS	\$4.10	\$4.19	\$4.28
x P/E Multiple	16.5x	16.5x	16.5x
Discount	-10%	-5%	5%
<b>Valuation</b>	<b>\$61.00</b>	<b>\$66.00</b>	<b>\$74.00</b>
Assumed CECONY ROE	8.8%	9.0%	9.2%

Source: Company filings, FactSet, UBS estimates

# Dominion Resources

*Expect an in-line quarter with milder weather and lower farmout activity already baked in. Lower hedge pricing for Millstone is also expected.*

For 1Q16, we expect D to report an in-line result \$0.97 vs. \$0.96 consensus and the \$0.97 midpoint of guidance that was released midway through the quarter and was based on milder weather than last year (followed by a somewhat mild March). The company continues to cite weather normalized utility sales growth of ~1% and higher merchant gen power margins offset with lower capacity payments, lower farmout revenues, and share dilution. Utility O&M should increase 1%-2%. Utility generation is expected to be down -\$0.02 including -\$0.04 of weather offset with higher ratebase and lower capacity expense as NUG contracts rolled off in 4Q15. At merchant gen, there were no maintenance outages at Millstone or Fairless in both 1Q16 and 1Q15, while D has guided to lower merchant results for the quarter due to lower hedge pricing, with Millstone 83% of 2016 hedged at \$51.93 (vs. 88% of 2015 at \$57 in 1Q15) and Fairless (unhedged) is in a constrained location with less impact. On Marcellus farmout acreage, we don't expect any additional activity announcements for 1Q vs. a +\$0.08 pickup in 1Q15 from \$65M-\$70M of Marcellus contracts. We still expect \$450M-\$500M of potential total pre-tax incremental earnings from 2015-2020, with ~\$340M-\$350M signed as of December 31<sup>st</sup> (earnings ramp up separately from signings). The company continues to guide to a lower income tax rate primarily as a result of booking non-regulated solar ITCs.

**Figure 98: Dominion Resources 1Q16 vs. 1Q15 Walk**

Last year vs Guidance	1Q15 ABS	1Q16 Low	1Q16 High	1Q16 Mid		1Q15A	0.99
VEPCO (weather normalized)						1Q16 vs normal	-
Elec Dist	246	210	225	218		VEPCO (weather normalized)	
Elec Trans	156	170	185	178		Elec Dist	(0.03)
Utility Gen	475	435	475	455		Elec Trans	0.02
D&A	(238)	(245)	(250)	(248)		Utility Gen	(0.02)
Regulated Gas (weather normalized)						D&A	(0.01)
Gas Dist	115	100	115	108		Regulated Gas (weather normalized)	
Gas Trans	333	250	275	263		Gas Dist	(0.01)
D&A	(65)	(65)	(65)	(65)		Gas Trans	(0.08)
Merchant Gen	167	140	175	158		D&A	-
D&A	(31)	(40)	(40)	(40)		Merchant Gen	(0.01)
Interest	(223)	(230)	(220)	(225)		D&A	(0.01)
Corp & Other	(24)	(20)	(20)	(20)		Interest	(0.00)
Income Taxes	(327)	(185)	(210)	(198)		Corp & Other	0.00
Income Tax Rate	36%	26%	25%	25%		Income tax rate	0.14
Operating Earnings after-tax	584	520	645	583		Dilution	(0.01)
Shares	590	600	598	599		<b>1Q16E</b>	<b>0.97</b>
<b>EPS</b>	<b>0.99</b>	<b>0.87</b>	<b>1.08</b>	<b>0.97</b>		<b>Consensus</b>	<b>0.96</b>
<i>EPS Guidance Range</i>				<i>0.90-1.05</i>		<b>1Q16 Guidance</b>	<b>0.90-1.05</b>
						<b>2016 Guidance</b>	<b>3.60-4.00</b>

Source: FactSet, UBS estimates, company guidance in Dominion Supplemental Alternate Breakdown Structure Report

## Reducing estimates for lower merchant generation

Our estimates through 2018E come down a few pennies for the impact of lower power pricing on Millstone, with a steeper -\$0.18 drop in 2019E due to [lower pricing in the most recent New England Forward Capacity Auction](#). As we noted in February, guidance for 2016 was initiated about a nickel below our expectations at \$3.60-\$4.00 and we've reduced our 2016 estimate to \$3.79 vs. consensus \$3.79 (down from a prior \$3.85).

**If passed this Spring, Connecticut SB 345 may allow Millstone to participate in long-term utility contracting for passthrough to customers**

Management now expects 2017 results 5%-6% above the new 2016 range \$3.60-\$4.00, implying a midpoint about ~\$4.01 vs. consensus \$4.01 and UBS estimate \$3.88. Factors for 2017 include a lower expected growth rate from Blue Racer and a substantial ~\$0.20 EPS drop in solar ITCs. Ultimately, this is expected to be offset by accretion from the STR acquisition (we calculate ~\$0.10) prior to dropdown into DM at 8x EBITDA. For 2018+, the company continues to target (or now potentially exceed) 7%-9% off 2017E, which implies a midpt of \$4.33 for 2018E vs. our estimate of \$4.47 (consensus \$4.34). Our 2019E estimate of \$4.50 implies a 3-year annualized growth rate off the \$3.80 midpoint of 2016 guidance of 5.8%. See our earnings table below for a comparison of new vs. old growth guidance.

### **Millstone nuclear likely to be hit with New England gas pipelines**

With Forward Capacity Market pricing significantly lower in the latest auction, we turn our attention increasingly to the potential impact of the proposed Access Northeast gas pipeline, designed to bring in 1 bcf/d of gas from the Marcellus by 2019 for the purpose of supplying fuel for an incremental 5 GW of gas generation in New England. It seems increasingly likely that once this gas import capability is achieved, marginal energy pricing for Millstone (and other non-gas-fired baseload generation) will be significantly reduced, leaving the plant more dependent on the capacity market for revenue. Furthermore, [Massachusetts appears poised to pass legislation this year to require a significant ramping of renewables](#) and hydroelectric energy from Canada, further suppressing energy pricing for regional nuclear units.

### **Limited public equity issuances through the end of the decade**

Aside from the \$750M equity issued recently to finance the STR acquisition and general corporate purposes, no further equity through at least 2020 is contemplated. Consistent with the plan announced at the Analyst Day in February to raise \$4.0B-\$4.5B of equity from 2015-2018 (and none afterward), D is now finished with public equity issuances through at least 2020 having raised \$500M from secondary equity in 1H15, having \$2.1B of existing mandatory convertibles outstanding, and the elimination of \$0.5B-\$1.0B of planned equity linked security offerings with a \$0.5B 3-year note offering. As noted above, the extension of bonus depreciation helps and \$300M of annual DRiP *will* continue. Cash proceeds from recently announced solar sales to SUNE have exceeded expectations ([see our 1/28 downgrade report](#)). Our 2019 estimate assumes ~\$300M of stock repurchases from expected strong cash flows once the Cove Point export facility is in operation, expected to generate about \$700M/yr cash.

**D converted \$550M of mandatory converts on April 1, expects to do another \$550M on July 1, 2016, and another \$1B on July 1, 2017**

Figure 99: Dominion Resources EBITDA and EPS, UBS estimates vs. Guidance vs. Consensus 2014A-2019E

2016 Guidance vs 2015 Actual Results and UBS 2016E-2019E										
Estimates by Segment (EBITDA) using ABS				UBS						
	EBITDA	EBITDA	EBITDA	FY16 EBITDA Guidance			UBSe			
	2014A	2015A	2015E	Low	High	2016 Mid	2016E	2017E	2018E	2019E
<b>VEPCO</b>										
Electric Distribution	905	870	870	855	885	870	870	937	993	1,048
Electric Transmission	588	656	656	740	765	753	756	853	947	1,038
Utility Generation	1,726	1,850	1,850	2,005	2,085	2,045	2,042	2,108	2,129	2,165
Virginia Power - Corp Adjusted	-	(1)	-	-	-	-	-	-	-	-
VEPCO DD&A	(878)	(951)	(951)	(1,030)	(1,040)	(1,035)	(1,037)	(1,041)	(1,071)	(1,131)
<b>VEPCO Adjusted EBIT</b>	<b>2,341</b>	<b>2,424</b>	<b>2,424</b>	<b>2,570</b>	<b>2,695</b>	<b>2,633</b>	<b>2,631</b>	<b>2,856</b>	<b>2,998</b>	<b>3,120</b>
<b>Regulated Gas Ops</b>										
Gas Distribution	327	359	359	350	370	360	360	434	473	512
Gas Transmission (DTI, CP Import)	1,114	1,066	1,066	1,045	1,115	1,080	993	969	1,121	1,128
Cove Point Export, Prod Svcs, Other	-	-	-	-	-	-	82	161	548	526
Dominion Midstream LP Minority Interest (after tax)	-	-	(24)	-	-	-	(96)	(113)	(143)	(210)
LP Minority Interest % (UBSe)	31.5%	31.3%	31.3%	-	-	-	39.0%	45.1%	50.9%	58.1%
GP Distributions (after tax)	-	0	0	-	-	-	3	16	38	81
Gas Operations DD&A	(243)	(262)	(262)	(270)	(270)	(270)	(270)	(290)	(310)	(322)
<b>Total Regulated Gas EBIT</b>	<b>1,198</b>	<b>1,163</b>	<b>1,139</b>	<b>1,125</b>	<b>1,215</b>	<b>1,170</b>	<b>1,073</b>	<b>1,178</b>	<b>1,726</b>	<b>1,714</b>
<b>Merchant Generation EBITDA</b>	<b>459</b>	<b>594</b>	<b>594</b>	<b>520</b>	<b>605</b>	<b>563</b>	<b>564</b>	<b>580</b>	<b>643</b>	<b>593</b>
Merchant DD&A	(98)	(138)	(138)	(175)	(175)	(175)	(175)	(170)	(166)	(162)
<b>Total Merchant Generation EBIT</b>	<b>361</b>	<b>456</b>	<b>456</b>	<b>345</b>	<b>430</b>	<b>388</b>	<b>389</b>	<b>409</b>	<b>477</b>	<b>431</b>
<i>Previous Merchant Generation EBIT (last update)</i>							389	425	502	584
<b>Corp &amp; Other</b>	<b>(49)</b>	<b>(97)</b>	<b>(97)</b>	<b>(45)</b>	<b>(35)</b>	<b>(40)</b>	<b>(39)</b>	<b>(42)</b>	<b>(44)</b>	<b>(47)</b>
<b>Total Adjust EBIT</b>	<b>3,851</b>	<b>3,946</b>	<b>3,922</b>	<b>3,995</b>	<b>4,305</b>	<b>4,150</b>	<b>4,054</b>	<b>4,402</b>	<b>5,156</b>	<b>5,218</b>
Interest expense	907	898	898	950	930	940	970	1,012	1,192	1,152
Income Taxes	925	984	984	795	810	803	773	1,016	1,212	1,274
Eff Income tax rate	31.4%	32.3%	32.5%	26.1%	24.0%	25.0%	25.1%	30.0%	30.6%	31.3%
Non-controlling Interests	16	24	0	100	90	95	-	-	-	-
<b>Net Income</b>	<b>2,003</b>	<b>2,040</b>	<b>2,040</b>	<b>2,150</b>	<b>2,475</b>	<b>2,313</b>	<b>2,311</b>	<b>2,374</b>	<b>2,753</b>	<b>2,792</b>
Shares Outstanding	585	594	594	610	608	609	609	612	616	620
<b>EPS</b>	<b>3.43</b>	<b>3.44</b>	<b>3.44</b>	<b>3.52</b>	<b>4.07</b>	<b>3.80</b>	<b>3.79</b>	<b>3.88</b>	<b>4.47</b>	<b>4.50</b>
<i>Previous UBS Estimates</i>							3.80	3.90	4.47	4.68
Consensus			3.44				3.79	3.92	4.34	4.75
<i>EPS drop from higher effective tax rate assuming reduced ITCs 2017+</i>								(0.27)	(0.35)	(0.41)
CAGR of midpoint of 2016 guidance to UBSe 2019						3.80				5.8%
Guidance of 5%-6% from '16-'17 off 2016 base guidance										
\$3.60-\$4.00 and 7%-9% from '17-'20				3.60	4.00	3.80	3.80	4.01	4.33	4.68

Source: UBS estimates, company filings, FactSet

## Raise PT \$3 to \$74 as roll forward to 2018E multiples and reduce merchant capacity value

Our price target comes up \$3 for higher peer utility P/E multiples since our last valuation in February, partially offset -\$1 as a result of lower merchant generation capacity value given the expected drop in 2019 forward capacity market revenues (we normalize our 2018E EBITDA for the drop, with higher revenues in 2018 offset with lower revenues in 2016 and 2017). We continue to view D as fairly valued given moderately increased uncertainty over midstream growth prospects in the Marcellus and Utica shales as well as the ability of DM to fund accretive acquisitions capable of supporting 22% LP distribution growth beyond the mid 2020's. We apply a 1x premium to the average 2018E P/E for VEPCO and the gas utilities, a 7x 2018E EV/EBITDA for merchant generation and 5x EV/EBITDA for remaining gas retail. For the midstream segment, we treat Phase 1 assets (through 2020) as dropdowns to DM and value them as the sum of discounted cash flows from LP and GP distributions at an 8.5% discount rate and 2.0% terminal growth rate, consistent with the UBS PT of \$39 for DM. For the Phase 2 midstream assets that drop down later in the decade and post 2020, we start with a base value at 11x 2018E EV/EBITDA and then add only 80% of the incremental value for MLP treatment at the same discount and terminal growth rates used for Phase 1 (100% would add another <\$0.50/sh).

**We maintain our wider concerns on earnings quality, particularly with the weaker growth YoY exhibited in 2015**

**Figure 100: Dominion Resources Sum-of-the-Parts Valuation on 2018E**

Dominion (D) Sum of the Parts Analysis - UBSe							
	2018E Adj. EBITDA	EV/EBITDA			Enterprise Value		
		Downside	Base	Upside	Downside	Base	Upside
Dominion Merchant Generation	467	6.0x	7.0x	8.0x	2,801	3,268	3,735
Hedge Value	(22)	6.0x	7.0x	8.0x	(132)	(154)	(176)
Normalize to 2019 capacity price	(120)	6.0x	7.0x	8.0x	(719)	(839)	(958)
Dominion Energy (DTI & Iroquois)	1,120	10.0x	11.0x	12.0x	11,196	12,316	13,435
Dominion Midstream Partners Minority Interest	(97)	10.0x	11.0x	12.0x	(972)	(1,069)	(1,166)
Dominion Retail	61	4.0x	5.0x	6.0x	245	306	367
<b>Total / Implied</b>	<b>1,409</b>	<b>8.8x</b>	<b>9.8x</b>	<b>10.8x</b>	<b>\$ 12,419</b>	<b>\$ 13,828</b>	<b>\$ 15,236</b>
<i>Value per Share</i>					<b>\$ 20.16</b>	<b>\$ 22.45</b>	<b>\$ 24.73</b>
<b>Phase 1 MLP through 2020</b>							
Discount rate applied to LP and GP distributions					10.0%	8.5%	8.5%
Terminal growth rate applied to LP and GP distributions					0.0%	2.0%	4.0%
LP Distribution Equity Value NPV					1,377	2,110	2,946
GP Distribution Equity Value NPV					1,151	1,866	2,811
PV of Compensation for Dropdowns from DM					3,283	3,452	3,452
add: NPV of 2016 and 2017 cash flows from Cove Pt Import					347	347	347
<b>Total Equity Value of MLP Phase 1</b>					<b>\$ 6,158</b>	<b>\$ 7,774</b>	<b>\$ 9,556</b>
<i>Value per Share</i>					<b>\$ 10.00</b>	<b>\$ 12.62</b>	<b>\$ 15.51</b>
<b>Phase 2 2018+</b>							
LP Distribution Equity Value NPV					1,780	2,798	3,804
GP Distribution Equity Value NPV					2,226	3,625	5,269
PV of Compensation for Dropdowns from DM					5,422	5,936	5,936
Minus DTI, LDCs, & Iroquois Equity Value (before MLP dropdown)					(11,663)	(11,663)	(11,663)
<b>Total Potential MLP Phase 2 Incremental Uplift to SOP</b>					<b>\$ (2,235)</b>	<b>\$ 697</b>	<b>\$ 3,347</b>
Probability					80%	80%	80%
<b>MLP Phase 2 Incremental Uplift to SOP</b>					<b>\$ (1,788)</b>	<b>\$ 557</b>	<b>\$ 2,677</b>
<i>Value per Share</i>					<b>\$ (2.90)</b>	<b>\$ 0.90</b>	<b>\$ 4.35</b>
<i>Net Implied GP Value per Share</i>					<b>\$ 4.76</b>	<b>\$ 7.74</b>	<b>\$ 11.41</b>
less Total Dominion net debt						(28,344)	
netting VEPCO-associated debt						11,030	
netting VEPCO debt allocated to HoldCo (assuming lever up to 60% debt/cap)						1,888	
netting Gas LDC-associated debt						1,265	
netting MLP Phase 1 debt allocated to HoldCo (at 3.5x EBITDA)						3,603	
add: NPV of Merchant Generation Hedges						279	
<b>Net Energy/Generation Debt</b>					<b>\$ (10,280)</b>		
<i>Value per Share</i>					<b>\$ (16.69)</b>		
<b>Dominion Energy, MLP, Merchant Generation, and Retail</b>					<b>\$ 6,509</b>	<b>\$ 11,879</b>	<b>\$ 17,189</b>
Current Number of Shares outstanding					616	616	616
<b>Dominion Energy, MLP, Merchant Generation, and Retail per Share</b>					<b>\$ 10.57</b>	<b>\$ 19.28</b>	<b>\$ 27.90</b>
	Peer P/E Multiple	16.5x	Premium	1.0x			
<b>Dominion Delivery</b>	2018 Net Income	P/E Multiple					
Electric	353.83	16.5x	17.5x	18.5x	5,838	6,192	6,546
Transmission	353	16.5x	17.5x	18.5x	5,826	6,179	6,532
Dominion Generation-Utility	1,008	16.5x	17.5x	18.5x	16,632	17,640	18,648
<b>Total VEPCO Net Income</b>	<b>1,715</b>	<b>16.5x</b>	<b>17.5x</b>	<b>18.5x</b>	<b>28,295</b>	<b>30,010</b>	<b>31,725</b>
<i>Value per Share</i>					<b>\$ 45.93</b>	<b>\$ 48.72</b>	<b>\$ 51.50</b>
<b>Gas Distribution LDCs</b>							
East Ohio	185	16.5x	17.5x	18.5x	3,059	3,245	3,430
Hope Gas	10	16.5x	17.5x	18.5x	172	182	192
<b>Total Gas Distribution Net Income</b>	<b>196</b>	<b>16.5x</b>	<b>17.5x</b>	<b>18.5x</b>	<b>3,231</b>	<b>3,427</b>	<b>3,623</b>
<i>Value per Share</i>					<b>\$ 5.24</b>	<b>\$ 5.56</b>	<b>\$ 5.88</b>
Current Number of Shares outstanding					616	616	616
<b>Dominion Regulated Utilities SOP Value (\$/sh)</b>					<b>\$ 51.18</b>	<b>\$ 54.28</b>	<b>\$ 57.38</b>
<b>Total Equity Value per Share</b>					<b>\$ 62.00</b>	<b>\$ 74.00</b>	<b>\$ 85.00</b>

Source: UBS estimates, company filings, FactSet

- We continue to see a positive skew to our EPS at VEPCO, suggesting the potential for positive revisions over time.
- For the non-regulated solar business, we continue to assign minimal value given uncertainties regarding the future of federal investment tax credits, so our PT is immaterially affected by our assumption of a higher effective tax rate in 2017+. While there has been little clarity, we continue to assume relatively limited earnings are attributable to the solar ITC assets after initial contributions (they contribute cash flow, with likely negligible earnings).

*For additional context, please refer links to relevant recent reports below:*

[3/30/16 Dousing the New England Grid](#)

[2/12/16 Read All About It: Why The New England Print Matters](#)

[2/11/16 Pouring Cold Water on New England Power](#)

[2/2/16 D: Going West for the Quest](#)

[2/1/16 DM: Solid Quarter, Drop Pipeline Enhanced](#)

*(report from Shneur Gershuni)*

[2/1/16 STR: Combining with Dominion Resources](#)

*(report from Shneur Gershuni)*

[1/29/16 A Plainer Domain \(Downgrade to Neutral\)](#)

[11/2/15 Big Projects on Track](#)

[9/18/15 Embedding the Auction Uplift \[VEPCO\]](#)

[9/11/15 Feasting on a Smorgasbord of Power & Utility Updates \[Annual D Update in September\]](#)

[9/9/15 D-eveloping the Partnership \[SUNE\]](#)

## **Questar acquisition opportunities focused on gas distribution and gas pipelines**

With STR already planning to sell the Southern Trails pipeline, D is focused on the growth opportunities from the Questar pipeline, intending to drop only the pipelines into the MLP (about \$179M EBITDA of a total \$425M MLP-eligible assets), while holding utility Questar Gas and Wexpro reserves at the parent. D does not intend to do any speculative drilling at Wexpro and would only drill if the cost of drilling was included in a cost of service contract (similar to the XEL framework). STR's utility growth is also projected to be robust, with 1.5%-2.0% growth in Utah and the utility's decoupling clause adding to the favorable profile. The company's Wyoming and Utah utilities are expected to file ratecases on March 3rd. The deal is expected to close by year-end and is to be financed by the assumption of ~\$1.6B STR debt, an additional \$1.5B of parent debt, \$500M of D equity, and a combo of \$2.4B D and 3-yr converts and dropdown cash from Dominion Midstream Partners (DM) (we assume \$1.8B/\$0.6B). Management states that there is strong interest from the current major holders of DM to expand their positions and suggests that a private offering of public stock may be possible.

## **Evidence of a slowdown for Dominion's Eastern shale-based gas infrastructure business**

Rather than the new plant planned for the Lewis complex in 2H15, management is now indicating a new third unit at either Natrium or Berne may take its place in 2016 once market conditions support it, if at all. We view this as an early indicator of possible pullbacks in Marcellus/Utica shale supply as a result of the severely depressed natural gas pricing in recent months/years. While we view this as reason for caution, we continue to note that most of Blue Racer's feedstock comes from the sweet spot of the Utica, perhaps the most prolific shale in the US, with

over 500 producing wells and another ~500 drilled and awaiting D's expansion of takeaway and processing capacity.

**That said, Dominion's largest growth projects remain on track**, with the LNG export facility at Cove Point still slated for 1H18 and now 56% complete. Further, Atlantic Coast Pipeline is poised to come online in 2H18 with surveying and pipeline engineering ~90% complete and ~70% of project materials procured. Additionally, Dominion is well positioned to capture continued gas demand growth across the Southeast with additional pipes and expansion to existing routes. We believe its network would well ultimately extend deep into the South via GA and FL, as well as proliferate in markets like NC as new plants contemplated under CPP compliance seek gas service. Its utility-driven demand growth, rather than E&Ps that still driven the *core* midstream growth. Dominion appears to be poised to pivot *towards* this more attractive strategic direction. Notably, this should also preserve the premium quality of its midstream assets given limited counterparty credit concerns, which remain a clear overhang elsewhere in the midstream sector.

**D has 13 other growth projects underway at \$1.2B of investment to move ~2 bcf/d by the end of 2018.** This includes 9 demand-driven "Market Access" projects in the mid-Atlantic, mid-West and Southeast. These include connections for CPV St. Charles and Keys Energy Center, New Market and Leidy South projects from Leidy, PA, Edgemoor in South Carolina, and the Western Access Project in Ohio. FERC has already approved 3 expansion projects since June and D has another 4 filings submitted. A new filing is expected shortly for a Charleston SC project.

**New farmout expected in 2016.** In September, D announced a 16K-acre farmout of development rights in Utica for the first time, where drilling is tougher (3000 ft. deeper) but potentially more productive. Another 160K acres remain available in Utica for further transactions. The plan is still for \$450M-\$500M of potential total pre-tax earnings from 2015-2020, with \$340M complete as of Dec 31. The 16K-acre Utica farmout was already built into guidance and might be somewhat comparable to an earlier 11k announcement that added \$27M of EBIT. However, no specific EBIT detail has been given and each arrangement is unique. While still occurring, the question is whether drilling activity will slow in the lower gas price environment alongside pressure from E&P companies.

## Solar ITC dropoff in 2017 even steeper than we expected

As we've noted previously, for the ~530 MW of contracted solar coming online in 2016 (Three Cedars and Four Brothers), we expect 80% to qualify for the 30% ITC credit on a value of about \$750M. Of this \$180M (\$0.28/sh), we had originally assumed a drop of -\$0.07 in 2017 as the company seeks to fill the earnings cliff with new projects. However, management is now guiding to a -\$0.20 drop in ITC benefits in 2017 to a new level of about \$0.10-\$0.15 EPS, which we now incorporate into our estimates. *No comment on 2018 plans yet, although presumably this would decline substantially.*

**As a separate part of the Questar deal, Dominion has committed about \$1B for three solar facilities in Beaver, Iron and Millard counties, Utah**

Baselines for Solar ITCs in management guidance:

- \$0.26 in 2015
- \$0.30-0.35 in 2016
- \$0.10-0.15 in 2017

As a separate part of the Questar deal, Dominion has committed about \$1B for three solar facilities in Beaver, Iron and Millard counties, Utah, which are backed by long-term power purchase agreements (PPAs) with local electric utilities.

**Ratebase solar in VA.** Management continues to emphasize 400MW of VEPCO solar through 2020 (legislation allows for 500 MW) under the state's accelerated compliance efforts. The state could yet see its efforts pay off as it would likely qualify for early action credits potentially as soon as the program is implemented. VEPCO recently signed a partnership with the state of Virginia to provide up to 110 MW of contracted solar. On Oct 1, VEPCO announced a proposal to build 3 additional projects totalling 56 MW by Dec 2016 for ~\$129.5M and filed with the Virginia State Corporation Commission (SCC) for certificates of public convenience and necessity. Another 20-MW facility in North Carolina was purchased in September to supply Norfolk Naval Station under a 10-year sales contract. The 400-MW program is planned to cost ~\$700M, adding ~\$0.07 to 2016 estimates. VEPCO is also requesting recovery through a rider clause that would take effect on Dec 1, 2016. By comparison, SO pursued a ~500 MW program at GA Power at the commission's request.

### **Rider review hits ROEs slightly; understanding the word "consecutive"**

In Virginia, regulators reviewed certain legacy limited issue rate riders under last year's legislation and reduced the ROE for these riders from 10.0% to 9.6%, with a total impact of about -\$0.005/sh to EPS. Furthermore, under the current suspension of biennial rate reviews, the next review period for possible refunds is set to be 2020-2021 with a rate change possible after two consecutive periods of overearning. It has been widely assumed that this means two consecutive reviews after the suspension period, with the next rate change possible in 2024. However, the company notes that this is actually a contested issue, with the word "consecutive" being taken by regulators to include the last 2013-2014 period before the suspension. Since regulators found the company just slightly overearning in this last period at 10.89% vs. a max 10.70%, it appears that a second period of overearning from 2020-2021 might result in a rate change somewhat earlier than previously expected in 2022.

### **Utility benefits from capacity payments and lower O&M during the suspension of biennial reviews**

We continue to see the potential for \$0.05-\$0.08/sh of earnings benefits from PJM capacity revenues as a result of a net long generation position at the utility. VEPCO began what is effectively a nine-year rate freeze under enabling legislation in Feb 2015 that suspends biennial rate review periods for five years through the end of 2019. Increases in capacity revenues that would normally offset customer costs will instead accrue to investor benefit during this period. Furthermore, accelerated spending in 2013/14 effectively kept ROE low for the 2015 biennial rate review, setting up potential for lower O&M and earnings beats later. While fuel and purchased power remain subject to annual review under a separate fuel rider, we also see expiring PPAs as possible justification for new self-build generation within ratebase under rate riders should this option be deemed beneficial under annual IRPs.

### **D a "net beneficiary" of bonus depreciation**

D expects a total \$2.5B cash benefit from deferred tax effects over the next several years as a result of the extension of bonus depreciation. With this among the biggest focal points for investors of late, we believe management could be well

positioned to tout the resiliency of their equity needs, particularly to fund *additional* growth slated for the 2019 and 2020 periods. While utility ratebase will experience some decline from accelerated depreciation and D may lose the ability to claim the Section 199 domestic production and manufacturer's tax deduction, we expect D to be a material beneficiary of the 5-year extension of bonus depreciation, largely as a result of tax deferrals and savings for major non-regulated projects such as Cove Point and ACP. Management noted that for 2015, since the new law was retroactive back to January 1, it did not allow the company to take \$0.03 EPS of tax deductions anticipated in fourth quarter guidance.

## Integrated Resource Plan upside for VEPCO

VEPCO will file the next update by May 1 with more specific plans, including a preferred option of the plans listed below. The company filed its 2015 Integrated Resource Plan (IRP) for Virginia and North Carolina on July 1 for the period 2016-2030 and expects to put forward more specific plans this year. Instead of the usual "preferred plan", the filing includes four options listed below to comply with anticipated EPA Clean Power Plan rules. All plans include the completion of the Brunswick and Greenville CCGTs by 2016 and 2019, respectively, as well as 400 MW of utility-owned regulated solar by 2020 and another 400 MW of non-utility solar by 2017. These plans are considered by management to be a starting point for further discussion about the preferred path forward given uncertainty over national and state-level carbon and clean power goals, with a more definitive plan expected next year with the 2016 IRP.

- o Plan A: Solar, characterized by a high concentration of utility-scale solar resources (4,000 MW by 2040);
- o Plan B: Co-fire, including using natural gas to partially fire eight Dominion-owned coal powered units to reduce carbon intensity;
- o Plan C: Nuclear, designed to include construction and operation of North Anna Unit 3, providing an additional 1,453 MW of nuclear-powered generation at the Company's North Anna Power Station; and
- o Plan D: Wind, including significant on-shore (247 MW) and offshore (2,016 MW) wind development.

**VEPCO will file the next update by May 1**

## Major utility generation projects on schedule

On the 4Q call, D reported that the 1.4-GW, \$1.2B Brunswick County CCGT project is now 96% complete with a mid-2016 in-service date. The utility also filed for a certificate of public convenience and necessity in July 2015 for the proposed 1.6-GW, \$1.3B Greenville County CCGT. Hearings were held in Jan 2016 and an order was received from the SCC in April for Dec 2018 in-service. Contracts have already been executed with MH Power Systems for the combustion turbine procurement and with Fluor for the engineering, procurement and construction (EPC) contract. Mostly on track with \$19.2B growth capex plan from 2015-2020 (7% CAGR), which includes an \$7.1B for T&D (8% CAGR) at VEPCO driven by customer sales growth above 1%, strategic undergrounding (somewhat delayed into 2016), \$700M/year for transmission projects, and substation security. On the generation side, D plans \$4.0B of utility spending (5% CAGR) and another \$1.2B for merchant investment (6% CAGR). This includes Brunswick, Greenville, and \$1.2B of planned spending on contracted unregulated solar from 2015-2016, which is mostly complete now having achieved 690 MW of solar acquisitions to date vs. a 625-MW goal. It also includes a plan for 400 MW of utility scale regulated solar in VA by the end of 2020 for ~\$700M (see above).

**Greenville received SCC approval in April and will begin construction soon**

# DTE Energy Co.

*Expect a strong miss on milder weather, the absence of revenue decoupling amortization, and lower REF volumes.*

We expect a ~dime miss for the quarter at \$1.44 vs. consensus \$1.53 as mild weather hurts -\$0.05 in addition to a negative comp vs. last year's very strong +\$0.17 impact from favorable weather in 1Q15. Load growth is projected to be flat for 2016+, with 1% customer growth offset with -1% energy efficiency and conservation. We also expect +\$0.07 from parent and other as a result of the timing of taxes last year that resulted in a heavy -\$25M loss in 1Q15 (this unwound over the remainder of last year so we expect more negative year over year comps in 2Q, 3Q, 4Q). Furthermore, the utility implemented a \$238M final rate increase on Dec 11, 2015 (including the elimination of a \$41M customer rate credit) following self-implementation of \$230M on July 1, 2015. Note that this was recently revised upward to \$242.7M on 2/23/16. The absence of \$10.6M/month of revenue decoupling mechanism (RDM) asset amortization in 1H15 reduces results by -\$0.12. O&M reinvestment in 1Q15 (while revenues were higher on favorable weather) results in a positive nickel comp. On the non-regulated side, we foresee -\$0.12 of lower REF and other P&I earnings as most income here was front end loaded in 2015 during a cold, high-output 1Q15 for its coal plant clients. We foresee a more modest flattish result for Midstream segment. At Energy Trading, we assume a more modest +\$6M result for the quarter vs. the \$12M earnings in 1Q15 (no specific driver here – simply assuming half).

**Figure 101: DTE 1Q16E vs. 1Q15 Earnings Walk**

EPS DTE Energy Earnings Walk	
\$1.65	1Q15A EPS
<b>(0.15) Unregulated Businesses</b>	
(0.12)	P&I: Higher volumes at REF sites in cold 1Q15 because of high volumes of coal for the strong weather. To offset, have coking coal for steel earnings at end of 2015 onwards.
(0.03)	Trading
0.00	Midstream: Continued investment in gathering system.
<b>(0.12) Regulated Utilities</b>	
(0.17)	1Q15 Weather vs normal +\$10M Elec and \$20M Gas (after tax) vs normal.
0.00	Storm expense (none) in 1Q15. Have had some storm activity in 1Q16
(0.05)	1Q16 Weather
0.00	Longer term, guiding to down outlook for the year but modest 1% growth offset by -1% EE in 2016+
(0.02)	Depreciation (Capex is more than 2x depn)
(0.01)	Property taxes
0.05	O&M (reinvestment) / lean: Weighted toward lean initiatives saving \$ in 4Q
(0.01)	Interest
0.19	Ratecase \$238M increase self implementation July 1, 2015 and final \$230M Dec 11, 2015
(0.12)	RDM was amortized in 2014 and 2015 +\$127M - was found to be illegal - filed for in the latest ratecase
0.00	DTE Electric - other
0.01	DTE Gas (weather normalized)
<b>0.06 Corporate &amp; Other</b>	
0.07	Corp & other: Had a large -\$25M loss in 1Q15 with eff tax rate unwinding throughout the year.
(0.01)	Dilution - issued \$200M in 2015
<b>\$1.44 1Q16E UBS</b>	
\$1.53	1Q16 Consensus
\$4.93	2016E UBS
\$4.94	2016 Consensus
4.80-5.05	2016 Guidance

Source: Company filings, FactSet, UBS estimates

## Few updates on Michigan energy legislation during recess

The legislature returned from Easter recess on April 12<sup>th</sup> with approximately 10 weeks left before the summer break. Currently the Senate Energy and Technology Committee has not finalized a bill but Chair Senator Mike Nofs (R) is expected to introduce a substitute bill and he commented on April 11<sup>th</sup> that the prospects of

energy legislation is “not dead”. Based upon media reports there continue to be multiple aspects of the potential legislation that are debated such as the ultimate terms for consumer choice/switching’ and renewables mandate/goal. We continue to highlight that this year is an election year in Michigan, so based on historical precedents it is unlikely that comprehensive legislation will be reviewed in the period after June.

As previously discussed, the legislation is likely to include new capacity requirements for competitive electric suppliers and a multi-year stayout period for commercial/industrials that stay with choice. These “fairness” provisions are expected to effectively end retail open access “organically” over time and create incentives for the utilities to build ~2 GW of new generation to help solve a MISO Zone 7 capacity shortage (about 1 GW from DTE). See our [4/15 report “Riding the MISO Roller Coaster”](#) for the latest capacity auction results, which included \$72/MW-day for Zone 7 (Michigan), a sharp uptick from the previous \$3.48/MW-day.

**NEXUS progressing forward with higher volumes**

Management reports forward progress, having ordered the compressors and pipeline construction materials. We continue to see reason for high confidence in the project given DTE itself is an anchor tenant (vs. the competing Rover pipeline project, which is more dependent on production shippers such as the troubled Ascent Resources). NEXUS currently has 1.75 bcf/d of interconnect agreements, with compression and looping handling volumes above 1.5 bcf/d (up to a max 2.0 bcf/d). Based upon the current timeline, in-service is scheduled for November 2017.

NEXUS currently has 1.75 bcf/d of interconnect agreements (up from 1.4 bcf/d at last report)

**Filed a new electric ratecase on February 1 with a future test year**

On February 1<sup>st</sup>, DTE filed an electric ratecase for a \$344M increase based on a 10.5% ROE (vs. 10.3% currently auth) on 37.49% of \$14.5B of ratebase and a future test year ending 7/31/17. Intervenor filings are due July 1<sup>st</sup>. (Docket C-U-18014)

Figure 102: DTE Electric Ratecase Procedural Schedule

DTE Electric Ratecase 2017 TY
Testimony (Staff and Intervenor) July 1, 2016
Self-Implementation Filing July 1, 2016
Self-Implementation Hearing July 8, 2016
Self-Implementation Brief July 12, 2016
Self-Implementation Reply Brief July 15, 2016
Rebuttal Testimony July 29, 2016
Motions to Strike August 3, 2016
Responses to Motions August 8, 2016
Cross-Exam Scheduled August 10-12 and August 15-19, 2016
Briefs September 16, 2016
Reply Briefs (RTW) September 30, 2016
PFD Target Date November 21, 2016
Exceptions to PFD December 8, 2016
Replies to Exceptions December 22, 2016

Source: Michigan Public Service Commission

## Looking through upside drivers

As illustrated in the table below, our 2017 and 2020 estimates (ex-Energy Trading) include \$0.10 and \$0.42, respectively, for incremental opportunity EPS. This incremental EPS includes (at 75% probability) new generation to serve returning ROA load, renewables expansion, and the replacement of coal units, with the breakout in the tables below. Excluding this \$0.42, our 2020 estimate remains within management's 5%-6% guidance range (plus a 2% contingency) at 5.7%. Including them, our 2016-2020 estimated EPS CAGR improves to 7.5%, still within the 2% contingency and somewhat better than the 6.5% realized CAGR over 2011-2015.

We continue to estimate that the incremental ~\$300M investment in the NEXUS pipeline (as a result of former partner Enbridge dropping out) boosts 2019E EPS by about \$0.10 and helps offset the expected \$0.15 drop in REF tax credits in 2020, allowing management to continue projecting a 7%-8% earnings CAGR through 2020 despite the reduction.

We also estimate that increasing NEXUS/Vector capacity from 1.5 bcf/d to 2.0 bcf/d could present another \$300M opportunity, which is now embedded within DTE guidance for \$25M of unspecified "whitespace" within the ~\$170M earnings projection for midstream in 2020 (represents continued ~10%-15% CAGR off 2016).

**At 100% probability for all opportunities, we estimate the total 2020E EPS upside potential would rise to \$0.56 and the 2016-2020E CAGR would rise to 8.1%. We estimate our valuation could increase another \$3/sh**

**Our estimates only include \$0.42 of this potential upside in 2020E (and only \$0.07 in 2016E)**

**Figure 103: Current DTE Guidance for 2016 & 2020 vs. UBS estimates and UBS estimates 2016-2020 CAGRs**

	2016 Guidance	2016 UBSe	CAGR 2016 thru 2020 Guidance	2020 Guidance	2020 UBSe	UBS CAGR 2016G-2020E
DTE Electric	\$584-\$600	\$586	5%-7%		\$731	5.4%
<u>Incremental Generation Capex Opportunities (ROA termination, Renewables, Coal-to-Gas) at 75% probability</u>						
		\$0			\$79	8.1%
DTE Gas	135-141	139	7%-8%		183	7.3%
Midstream	105-115	110	10%-15%	~\$170M	170	11.5%
Power & Industrial Projects	90-100	96		~\$105M	105	
Trading	0	0		0	0	
Parent & Other	(50)-(-46)	(44)			(46)	
<b>Total (without incrm'tl opportunities)</b>	<b>\$864-\$910</b>	<b>\$887</b>	<b>7%-8%</b>		<b>\$1,143</b>	<b>6.5%</b>
<u>Incremental Opportunities</u>		\$0			\$79	8.3%
EPS (without incrm'tl opportunities)	4.80-5.05	4.93	5%-6%	Implied Midpt 6.10	6.15	5.7%
<u>Incremental Opportunities EPS in 2019</u>						
Expected ROA Elimination		0.05			0.19	
Renewables		0.03			0.12	
2019-2025 New Gen		-			0.12	
<b>Total</b>		-			0.42	
<b>Total UBSe (with incrm'tl opportunities)</b>		<b>4.93</b>			<b>6.57</b>	<b>7.5%</b>
180M sh, with \$100M equity 2016						
Avg. Shares Outstanding		180			186	\$200M-\$300M equity 2016-2018 @ 50%-53% debt

Source: UBS estimates, company filings, FactSet

As illustrated in the table above, our 5.7% EPS CAGR through 2020E assumes no incremental opportunities at either the utilities or the unregulated segments. It also assumes the midpoint of the company's \$2.0B-\$2.6B investment range for gas storage and pipelines as the company proceeds with the NEXUS project at 50% ownership.

**At the indicated probabilities, our 2016-2020E EPS CAGR rises to 7.5% when including these incremental opportunities, within management's guidance of 5%-6% plus a 2% contingency**

## UBS estimates unchanged

Our estimates are unchanged, with only \$200M-\$300M of equity issuances expected through 2018 as a result of bonus depreciation. For 2019-2020, we resume our prior assumption of \$200M/year equity issuance. Our long-term projection for 2020E of 5.7% growth (7.5% with opportunities) continues to be in-line with guidance CAGRs of 5%-6% plus a 2% contingency. We break down our estimates in further detail for the various incremental opportunities in the sections below. At 100% probability for all opportunities, we estimate the total 2020E EPS opportunity would rise from \$0.42 to \$0.56 and the 2016E-2020E CAGR would rise to 8.1%. We estimate our valuation could increase another \$3/sh at 100%.

**Figure 104: UBS Earnings Estimates, 2014A-2020E**

UBS Estimates							
	2014A	2015E	2016E	2017E	2018E	2019E	2020E
DTE Electric	\$2.99	\$3.12	\$3.26	\$3.52	\$3.67	\$3.81	\$3.93
Incremental Generation Capex Opportunities			\$0.00	\$0.10	\$0.19	\$0.36	\$0.42
DTE Gas	\$0.79	\$0.77	\$0.78	\$0.82	\$0.88	\$0.95	\$0.98
Midstream	\$0.46	\$0.56	\$0.61	\$0.68	\$0.75	\$0.83	\$0.92
Power & Industrial Projects	\$0.51	\$0.56	\$0.53	\$0.59	\$0.65	\$0.71	\$0.56
Trading	\$15.85	\$0.11	(\$0.00)	\$0.00	\$0.00	(\$0.00)	(\$0.00)
Parent & Other	(\$0.74)	\$0.24	(\$0.24)	(\$0.35)	(\$0.32)	(\$0.28)	(\$0.25)
<b>DTE Energy</b>	<b>\$4.60</b>	<b>\$4.82</b>	<b>\$4.93</b>	<b>\$5.35</b>	<b>\$5.83</b>	<b>\$6.38</b>	<b>\$6.57</b>
Prior UBSe		\$4.82	\$4.93	\$5.35	\$5.83	\$6.38	\$6.57
<b>DTE Energy without incremental opt'y</b>	<b>\$4.60</b>	<b>\$4.82</b>	<b>\$4.93</b>	<b>\$5.25</b>	<b>\$5.63</b>	<b>\$6.02</b>	<b>\$6.15</b>
Street Consensus	\$4.60	\$4.82	\$4.94	\$5.26	\$5.63		
Midpoint of mgmt guidance 5%-6% from 2016 \$4.93 to 2020			\$4.93	\$5.20	\$5.48	\$5.78	\$6.10
Management guidance			\$4.80-\$5.05				

Source: UBS estimates, company filings, FactSet consensus

## Valuation: Raise PT \$7 to \$107 PT on higher peer utility multiple and roll forward to 2018E. Reiterate Buy rating on strong Michigan growth story

Our valuation is now based on a utilities 2018E sum-of-the-parts with a half turn premium P/E multiple for the electric utilities and a 1x premium for the gas utility. We assign EV/EBITDA for the unregulated businesses.

We continue to assume a 75% probability for the possible 1 GW of additional generation needed after Retail Open Access (ROA) is terminated (assumes all shopping customers return to utility generation service). We also assume a 75% probability for an additional 500 MW of renewable generation should the 2020 RPS be increased 5% next year. We give 75% credit for \$500M/year incremental new generation during the anticipated 2020-2024 replacement of coal-fired plants (we apply a discounted EPS back to our 2018E P/E multiple).

Figure 105: DTE Sum-of-the-Parts Valuation on 2018E

Business Segment	Prob	Valuation Metric	2018	Low Case Valuation Multiple	(\$s MM) Value	Base Case Valuation Multiple	(\$s MM) Value	High Case Valuation Multiple	(\$s MM) Value
<b>Regulated</b>									
DTE Electric		P/E	\$3.66	16.0x	\$10,650	17.0x	\$11,315	18.0x	\$11,981
Incremental ROA, Renewables Capex	75%	P/E	\$0.28	16.0x		17.0x	863	18.0x	1,218
Incremental 2020-2024 New Generation	75%	P/E	\$0.36	16.0x		17.0x	1,099	18.0x	1,551
DTE Gas		P/E	\$0.88	16.5x	2,633	17.5x	2,793	18.5x	2,952
<b>Regulated, Equity Value</b>					<b>\$13,283</b>		<b>\$16,070</b>		<b>\$17,703</b>
<b>Unregulated Business</b>									
Power Projects		EV/EBITDA	\$252	9.0x	\$2,268	10.0x	\$2,520	11.0x	\$2,772
Midstream		EV/EBITDA	\$238	11.0x	2,622	12.0x	2,860	13.0x	3,099
Trading		EV/EBITDA	\$1	4.0x	4	5.0x	5	6.0x	6
Parent & Other Overhead		EV/EBITDA	\$88	9.0x	792	10.0x	880	11.0x	968
Less: Parent Debt, Net (2018E)					(2,967)		(2,967)		(2,967)
<b>Unregulated, Equity Value</b>					<b>\$2,719</b>		<b>\$3,299</b>		<b>\$3,878</b>
<b>DTE Equity Value</b>					<b>\$16,002</b>		<b>\$19,368</b>		<b>\$21,581</b>
Fully Diluted Outstanding Shares (2018E)					182		182		182
<i>DTE Equity Value per Share without incremental opportunities</i>					<i>\$88.00</i>		<i>\$96.21</i>		<i>\$103.76</i>
<b>DTE Equity Value per Share including incremental opportunities at probability</b>					<b>\$88.00</b>		<b>\$107.00</b>		<b>\$119.00</b>

Source: Company filings, UBS estimates

*For additional context, please refer links to relevant recent reports below:*

[2/12/16 Running Leaner on Less Equity](#)

[10/26/15 Tooling Up for More in 2016 after Strong 3Q](#)

[9/30/15 Upbeat Analyst Day Saves More for Next Year](#)

[7/27/15 Votes of Confidence](#)

[4/27/15 A Tiger Roars Into Spring](#)

[4/10/15 CMS Energy: Making Up for Lost Time](#)

[2/17/15 Michigan's Engine to Drive Growth](#)

[12/12/14 Doubling Down on Detroit; Upgrade to Buy](#)

[9/12/14 Managing Michigan's Coal Transition & the MISO Upside Story](#)

## What's important for DTE Energy:

- **Clearing the path for new generation:** So as to not lose sight of the forest for the trees, the benefit we see for the utilities is that a bill would likely reduce the level of commercial/industrial choice customers by 80%-90% (to only 1%-2% of load) by reducing the financial incentives to remain a non-utility customer. This is the primary condition needed to justify the expected construction of nearly 2 GW of new gas-fired generation by CMS and DTE (combined) that would be required to avoid reserve margin shortfalls projected by 2020 in the recent MISO capacity forecast report.
- **Rate increase for DTE Electric:** On December 11<sup>th</sup>, DTE Electric received a final order for a \$230M rate increase based on a 10.3% ROE on 38.03% of \$13.4B ratebase, with a forward test year ending 6/30/16. The utility had self-implemented a \$230M increase in July 2015. Note that this was recently revised upward to \$242.7M on 2/23/16. *See above for our comments on the most recent 2017 test year ratecase filing.*
- **Energy efficiency (EE) impact ramps up:** DTE Electric's load forecast is essentially flat, with EE from increasing residential adoption and new technologies offsetting virtually all ~1% underlying annual customer and economic growth impacts. Nevertheless, on the industrial side, prospective projects may add up to an additional 0.5% incremental load. Management notes that favorable customer bill impacts from lower usage rates help provide headroom for needed reliability improvements, with ~\$65 average annual residential bill reduction supporting up to ~\$850M of investment.

- **Shifting the rates to improve business competitiveness:** In a separate docket, the PSC ruled on the rate design issue in the attempt to incentivize further economic development for heavy usage industrial customers. The decision specifically resulted in a 5% reduction for primary customers and a 4% increase for residential customers, less extreme of a shift than previously contemplated by some discussions. The impact of the rate design is largely similar to those for CMS' utility Consumers Energy. Case No. U-17689. With DTE amidst a 'big upgrade & replacement cycle', the company notes that even with a \$238M rate increase (\$230M self-implemented in July), large industrial customers have seen a 15% average rate reduction since 2013 while commercial customers have seen a 9% reduction, largely as a result of \$600M of surcharge reductions.

## Gas Utility Issues

- *See above for the latest NEXUS update.*
- **Filed a new gas ratecase on December 18, 2015.** The utility filed for a permanent rate increase of \$183M based on a 10.75% ROE on 38.77% of \$3.7B ratebase and a forward test year ending 10/31/17. The request includes \$32M of net costs currently recovered through the Infrastructure Recovery Mechanism (IRM), for a realized increase of only \$151M. Self-implementation will take place in November, before the heating season begins. In 2015, DTE had requested an acceleration of main replacement/renewal from the current 50-year timeline to 25 years, which would increase annual investment from \$80M up to \$130M to double the annual miles replaced to 160.
- **Expanding the midstream bucket.** Management has guided to total earnings contributions from its Gas Storage & Pipeline segment of \$170 Mn in 2020, up from \$145 Mn in 2019, reflecting 17% YoY growth ahead of the 10-15% promised segment growth. We flag exceptional confidence within this segment.
- **The Millennium pipeline is currently being expanded** to ~1.0 bcf/d as east-west spreads remain wide and New England remains constrained. The expansion is seen as a critical route to getting Marcellus gas to Eastern gas utilities. The company is constructing an 8-mile lateral (CPV Valley) to serve a proposed 650-MW CCGT (about 125 mmcf/d). A further expansion to 1.5-1.8 bcf/d is possible through looping and/or parallel pipe, but not likely to see anything announced before 4Q 2017.
  - This new build CCGT in downstate New York would be among the first merchant CCGTs built in the state since the downturn – and largely driven by the cheaper gas available off the pipe versus the regional prices available.
- **Midstream partnership with Southwestern** and opportunities for growth (filling in the "whitespace" in their growth charts). The midstream segment could grow significantly from additional gathering system development for Southwestern Energy (assuming the current projects continue to go well), with the two companies signing an agreement in November 2014 to expand the Bluestone gathering system in Susquehanna County by 50% (along with associated Bluestone pipeline capacity). Bluestone is expected to reach 1 bcf/d in 2Q16, with strong well results and the addition of Cabot volumes in 2014 driving expansion. Average daily volumes on Bluestone have been growing significantly faster than originally forecast and are currently at over 900 MMcf/day in Dec 2015 vs. forecasted 300 MMcf/day. *We note this partnership*

Notably, the pipelines segment improved \$7M in 2Q primarily due to volume growth in the Bluestone pipeline and gathering assets

Average daily volumes on Bluestone have been growing significantly faster than originally forecast and are currently at over 900 MMcf/day in Dec 2015 vs. forecasted 300 MMcf/day

Counterparty concerns continue to shadow execution

*has added substantially to investor consternation in the story, particularly given the counterparty credit and execution concerns pervasive in the MLP universe.*

- **Bolt-on acquisitions remain under consideration but no progress yet.** DTE is actively looking at possible acquisitions of existing projects, although no specific projects have yet met management's strict investment criteria yet, despite the distress of many of the midstream companies. We see capital market weakness for MLPs as possibly limiting competition for assets while also possibly removing any remaining incentive for management to consider an MLP structure for itself (or to sell its assets to one).
- **Addressing the expected 2020 falloff in tax credits for P&Is.** Reduced Emission Fuel (REF) business, which is currently operating in nine sites. Additionally, DTE is now operating a third-party REF facility with an operating agreement through 2020. Management continues to "work towards further optimization" of this segment, with the goal of generating significant cash flows to fund other non-utility growth projects. Emphasis for this segment remains on the CHP (Combined Heat and Power) opportunities in a cheap gas price environment, positioned to provide an array of products on a 'behind the meter' basis.

On the 4Q call, guidance for 2019 was reduced \$25M to \$120M (mostly lower Industrial Energy Services income) and the REF business is expected to experience a \$30M (\$0.15/sh) drop in tax credits in 2020. Management expects the tax credit drop in 2020 to be offset by many growth levers at that time, both at the utility through generation and other ratebased growth, as well as future additional midstream projects. We estimate that the upsizing of NEXUS to 50% (from the dropout of Enbridge) alone could increase 2019E earnings by ~\$0.10/sh. See above for details.

# Duke Energy

*This is one of the more controversial companies now with investors debating whether shares deserve a discount or a premium (seemingly no middle ground). With many investors still searching for 'cheaper' defensive utility plays, we see DUK retaining this position vs. peers. We think shares could prove bumpy in the near term as long-dated estimates reflect the dilutive impact of the sales; that said, the question is how much of the re-rating will occur prior to the announced sale.*

We expect DUK to report 1Q16 adjusted EPS of **\$1.07**, a full dime below consensus (\$1.17) due to unfavorable weather and Commercial comparisons. Weather in 1Q15 was +\$0.10 better than normal and the current quarter also appears to be below-average, further compounding the negative comparison. Excluding weather the utility should exhibit strong growth due to capital investments and the benefits of the NCEMPA purchase in July 2015. The comparable quarter included the conventional merchant assets which were sold to Dynegy in 2Q15 which further creates a large headwind for the quarter. On the topic of wind, the renewables segment was actually down YoY despite more capacity, highlighting the impact of the below-average wind generation last year.

**Between weather and commercial power (conventional and renewables) we forecast a greater YoY decline than consensus**

**Figure 106: DUK 1Q16E Earnings Walk**

Duke Energy 1Q16 Earnings Walk	
<b>\$1.24</b>	<b>1Q15A Adjusted EPS</b>
<b>Regulated Utilities</b>	
<b>(0.10)</b>	Weather vs Normal in 1Q15 +\$110Mn Pre-Tax Impact
<b>(0.05)</b>	Weather vs Normal in 1Q16
<b>0.02</b>	Capital Investments: \$0.08 riders for FY, AFUDC on large generation projects
<b>0.02</b>	O&M: Commentary to reduce in 2016 vs 2015; offset by 1Q16 storm costs
<b>0.01</b>	Load: Growth (~0.6% with 100 bps ≈ \$0.10 EPS FY)
<b>0.01</b>	Wholesale Growth: \$0.01-\$0.03 incremental in 2016 vs \$0.10 in 2015
<b>0.03</b>	Purchased NCEMPA July 31, 2015 for \$1.25Bn (full quarter)
<b>0.00</b>	Accretion from Piedmont Transaction: Expected to close in 4Q16
<b>(0.01)</b>	Depreciation, property taxes, interest, and other
<b>Commercial: Renewables &amp; Midwest Generation</b>	
<b>(0.13)</b>	Absence of Midwest Generation: \$90M in 2015, concentrated in 1Q15
<b>0.02</b>	Reversal of 1Q15 below-average renewable generation
<b>0.02</b>	Renewables - expect \$1B-\$2B incremental investment 2015-2017
<b>(0.02)</b>	Income taxes - reversal of tax levelization adjustment
<b>International and Other</b>	
<b>(0.01)</b>	Brazil: Impact of F/X (~\$0.015 annualized for 10% change)
<b>(0.02)</b>	NMC: Impact of Brent Crude (~\$0.015 annualized for \$10/bbl change)
<b>0.01</b>	Financing cost reduction from cash repatriation
<b>0.02</b>	Impact of Accelerated Stock Repurchase Program
<b>\$1.07</b>	<b>1Q16E Adjusted EPS</b>
<b>\$1.17</b>	<b>1Q16 Consensus</b>
<b>\$4.59</b>	<b>2016 UBSe EPS</b>
<b>\$4.61</b>	<b>2016 Consensus</b>
<b>\$4.50-\$4.70</b>	<b>2016 Guidance</b>

Source: Company filings, FactSet, UBS estimates

*For additional context, please refer links to relevant recent reports below:*

[2/22/16 Holding The Line on Growth](#)

[12/22/15 Brighter Setup for 2016; Upgrade to Buy](#)

[11/8/15 A Samba Reset](#)

[10/26/15 The Duke of North Carolina](#)

[8/10/15 Targeting a Samba Surprise](#)

[5/5/15 Even More Cash Coming](#)

## **What are the pivotal questions for DUK?**

### **Will DUK sell its troubled Brazilian hydroelectric plants?**

- **Process for international sale is still in early stages but continuing to move forward:** The last update from management was that they opened a dataroom in late March and was hopeful that it could provide more updates soon. We perceive a sense of urgency in the process (1) with Petrobras stating that it intends to divest its own local generation assets [i.e. avoid competition] and (2) a desire to complete the deal by year-end. The improvement in foreign exchange rates should help improve the prospects for an attractive price but we still expect meaningful dilution (~\$0.20/sh). This dilution calculation assumes that the sale is fairly tax efficient as Duke's prior cash repatriation was structured as a repayment of a parent note, mitigating that impact of a low cost basis.
- **Proceeds of the deal: All about debt pay-down.** All of the corporate level proceeds will be used to either pay down corporate debt/eg offset future issuances; this would appear to be debt in the range of ~3%, suggesting the range of EPS benefits is likely limited to less than \$0.05 under the best of situations. Between adding the more stable Piedmont and removing the bulk of the volatile international business we ultimately expect an improvement in the risk profile from the rating agencies.

The fact that management is committed to a sales process, rather than a JV, spin, suggests that there are limited avenues to mitigate the impact

Reducing debt appears to be a placeholder if management cannot find more accretive uses of the capital (ex. commercial renewables)

### **What are key factors influencing 2016+ growth?**

*Duke made good progress in both Indiana and North Carolina on proposals that faced notable regulatory and stakeholder pushback, respectively.*

- **Indiana transmission project achieves settlement; still waiting on the Commission to act:** Duke recently reached a settlement with some consumer and environmental groups related to its Indiana infrastructure plan under Indiana Senate Enrolled Act 560 on March 7<sup>th</sup>. As part of the agreement Duke is reducing the cost of the plan to \$1.4Bn from \$1.827Bn, ~\$200Mn of which relates to deferring smart meter investments that Duke can re-propose at a later date. Additionally the ROE on trackers will be set at 10% rather than the 10.5% requested (no change to ratebase at 10.5%). Rates under the plan will be phased in from 2017-2022 with ~0.75% annual inflation compared with ~1% previously). A decision from the Indiana Utility Regulatory Commission (IURC) is expected in mid-2016. For background Duke's original \$1.9Bn request was rejected in May 2015 due to a lack of supporting documentation for the planned investment cost (scope, confidence intervals, etc.).

SEA 560 allows the IURC to approve riders for a "transmission, distribution, and storage system improvement charge (TDSIC)"

- **North Carolina approved a revised Western Carolinas Modernization project (Foothills transmission project/Asheville Plant):** On February 29<sup>th</sup> the North Carolina Utilities Commission (NCUC) approved the revised Western Carolinas Modernization project. After receiving extensive feedback on its earlier proposal Duke adjusted its plan to retire and replace the 376 MW Asheville coal plant in NC with the construction of two 280 MW CCGTs in 2020. The primary change in the revised plan appears that Duke is delaying/cancelling the 190 MW simple cycle unit which had been planned by 2023, instead adding ~20MW of renewables and storage. The original plan had included a larger 650 MW natural gas-fired power plant (~\$750mn); a transmission substation near Campobello, SC, and a 40-mile, 230 kV line (~\$320mn). "Most" of this capex is incremental to DUK's February 5-year capital plan that called for \$41.75B of total capex from 2015E-2019E, including \$2.95B of "discretionary" spend (a minority portion is considered part of the discretionary bucket).
- **Coal ash update expected in June:** The next step is the NC Coal Ash Management Commission review of the DEQ basin ranking report which has a 60-day window from the April filing. By October Duke is required to disclose coal combustion residuals (CCR) closure plans for all basins. Currently \$1.3Bn of capital has been approved for the high-risk basins under the legislation and all spending is being deferred (both capital and O&M) into a regulatory asset to be decided in the next ratecase. For the remaining assets identified the North Carolina Department of Environmental Quality (NCDEQ) has given its recommendations but Duke is waiting for DEQ final approval.

On December 31<sup>st</sup>, the NCDEQ issued its draft coal ash pond classifications for all 14 of DUK's coal ash impoundments in North Carolina as required by the Coal Ash Management Act (CAMA) of 2014. Of the remaining ten facilities not specifically mentioned within CAMA as High Priority (see below), the draft recommends only Intermediate and Low priorities vs. the earlier Staff recommendation that all be considered High priority. Specifically, the draft proposes Intermediate classifications for W.S. Lee, Cape Fear, Weatherspoon, and Roxboro (east basin). A Low classification is proposed for Cliffside (two non-active basins), Roxboro (west basin), and the Mayo plant. Pending more analysis, a range of low-to-intermediate was proposed for the Allen Plant, Belews Creek, Buck, Cliffside (one active basin), and Marshall.

Under the CAMA, four sites already received a high priority designation written into the law itself: Asheville Plant (Asheville, N.C.), Dan River Steam Station (Eden, N.C.), Riverbend Steam Station (Mount Holly, N.C.) and Sutton Plant (Wilmington, N.C.). DUK has already begun excavation work at these sites in addition to two others: the Cliffside Steam Station (Mooresboro, NC) and the W.S. Lee Steam Station (Belton, SC). Furthermore, DUK has announced plans to build fully lined on-site landfills at Dan River, Sutton, W.S. Lee, and the Robinson Plant (Hartsville, S.C.). The Asheville plant will also be retired as part of the Western Carolinas Modernization project discussed previously.

The current asset retirement obligation is a probability-based assessment of what management estimates the clean-up/retirement costs will be on a discounted basis.

**We believe this could add as much as \$0.05-\$0.08 EPS incremental to prior expectations by 2019**

**The approved proposal is expected to cost ~\$1Bn, down \$100Mn from an earlier plan**

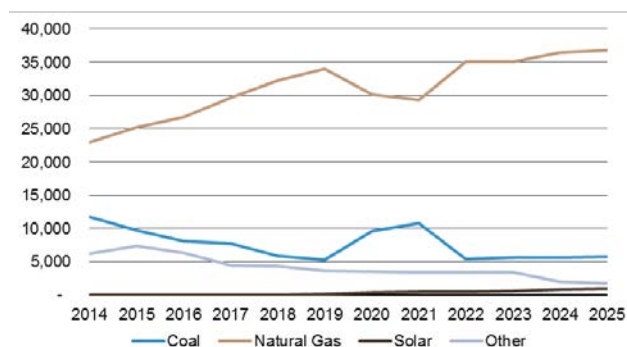
**Only approved capex for high-risk basins is included in Duke's plan today**

**As a reminder, coal ash ponds designated as high-risk must be excavated and closed by December 2019; intermediate-risk ponds must be excavated and closed by December 2024; and low-risk ponds must be closed by December 2029**

- **Drilling down into Florida utilities plans:** The Florida utilities filed their 10-year site plans on April 1<sup>st</sup> [\[details here\]](#) and conventional generation is expected to dominate the fuel mix. Solar is expected to represent <3% of the generation for each of Duke Energy Florida, Florida Power & Light, and Gulf Power, respectively. Duke plans to add 550MW of solar PV while NextEra is targeting 633MW (300MW incremental by 2021 to the ~225MW previously announced to be in-service by YE16). While the growth in renewables is significant, with limited net load growth forecasted 2015A-2025E (20-70bp) there is a natural constraint on deployment in the absence of new environmental standards.

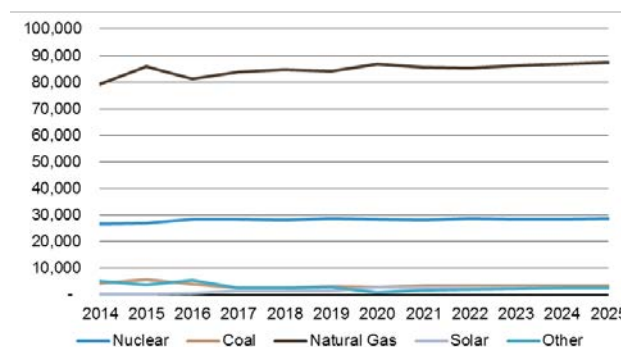
**DUK and NEE project ~150bp customer growth over the 10-year period but only ~50bp of net load expansion**

**Figure 107: Duke Energy Florida Forecasted Energy Sources (GWh)**



Source: Company filings

**Figure 108: Florida Power & Light Forecasted Energy Sources (GWh)**



Source: Company filings

While solar today is a tough economic proposition in the state given low priced mostly gas fired electricity there, the company currently sees demand from green-oriented C&I customers and anticipates lower cost technology in the future will ultimately make solar more financially competitive.

Further details are available in our recent note [‘The Battle Over The South’](#) discussing the dynamics between renewables and conventional generation in the southeast.

### What is the outlook for the Piedmont transaction and others?

- **North Carolina review this summer is the remaining item:** On March 14<sup>th</sup> the Tennessee Regulatory Authority (TRA) approved the change of control leaving the North Carolina Utilities Commission (NCUC) as the last regulatory approval necessary to close the transaction. [Hearings are scheduled for July 18<sup>th</sup>](#) and management continues to believe its target of closing by YE16 is reasonable. Duke completed the equity component of the financing on March 7<sup>th</sup> when it closed the forward sale of 10.64Mn shares at \$72Mn, raising gross proceeds of \$766Mn; this is likely at the top-end of the \$500-\$750Mn after fees. Duke plans to finance the balance of the transaction with holding company debt.
- **Beyond Piedmont, management discusses other potential opportunities:** Investors have scrutinized how large the contribution from non-recurring renewables tax credits are in ongoing earnings (up-front ITC and early-contract skewed PTC) but pipeline investments do not have the same ‘cliff’ concerns. For example, Duke disclosed that over 75% of its commercial power earnings originate from tax benefits, and investors have similarly been concerned by the magnitude of ITCs included in Dominion’s ongoing earnings.

**Duke is “looking to avoid the treadmill” for renewables EPS**

Dedicating capital to gas projects is far from a novel concept but the chorus of management team's expressing interest has grown lately with Duke (among peers) specifically looking for:

- Minimal/no commodity exposure
- Long remaining contract life with high quality counterparty
- Attractive valuation from a distressed owner in need of liquidity

In our recent meeting with Duke management, the company explained how important adding a high quality regulated gas company was to its portfolio, emphasizing that it plans to make Piedmont the core of its gas business which it plans to grow over time. Given how strategically Duke viewed Piedmont (management considered other companies) it relaxed its capital discipline to ensure that it won the competitive bidding process. Other examples of this trend include Emera-TECO, SO-AGL, and D-SCG (Carolina Gas Transmission). We flag that Emera in its acquisition of TECO noted it saw the deal as establishing its gas platform, with plans to seemingly scale the LDC beyond its traditional ratebase confines.

Utilities have largely focused on renewables utilizing their electric expertise to find relatively low risk investments but could gas compare in scale?

## EPS Estimates largely unchanged

Below we present our latest EPS estimates which includes neither any accretion from Piedmont nor dilution from an international sale.

**Figure 109: Updated Duke Adjusted EPS Estimates**

DUK EPS	2013A	2014A	2015E	2016E	2017E	2018E	2019E
UBSe	\$4.35	\$4.55	\$4.54	\$4.59	\$4.76	\$4.99	\$5.19
<i>UBSe International</i>	<i>\$0.60</i>	<i>\$0.61</i>	<i>\$0.32</i>	<i>\$0.28</i>	<i>\$0.27</i>	<i>\$0.26</i>	<i>\$0.26</i>
<i>Prior UBSe</i>	\$4.35	\$4.55	\$4.54	\$4.58	\$4.76	\$4.97	\$5.21
Consensus			\$4.54	\$4.61	\$4.77	\$5.01	\$5.19
Guidance			4.55-4.65	\$4.50-\$4.70		16-'20 Core	4-6%
UBSe 2016-2019 Core CAGR (ex-international)							4.7%

Source: Company filings, FactSet, UBS estimates

Expected accretion from this deal remains ~\$0.12/sh through 2020, albeit with the bulk of this accretion coming in nearer term rather than delayed; this would appear to contribute ~0.5% in CAGR growth through 2020 (this is presented in the 'upside' case in management's 4-6% range). We emphasize much of the upside here too is seemingly biased towards 2H-2018 and into 2019, as the ACP project reaches in service, with corresponding upside from direct earnings as well as corresponding projects). We also emphasize PNY accretion appears tied to specific generation project in-service and corresponding upside from the earnings attributable to this segment in 2015.

## Valuation: Maintain \$82 price target

Our valuation is based on a 2018E P/E methodology with a 5% premium. We upgraded shares to Buy in December as we believe that Duke can re-rate to a premium.

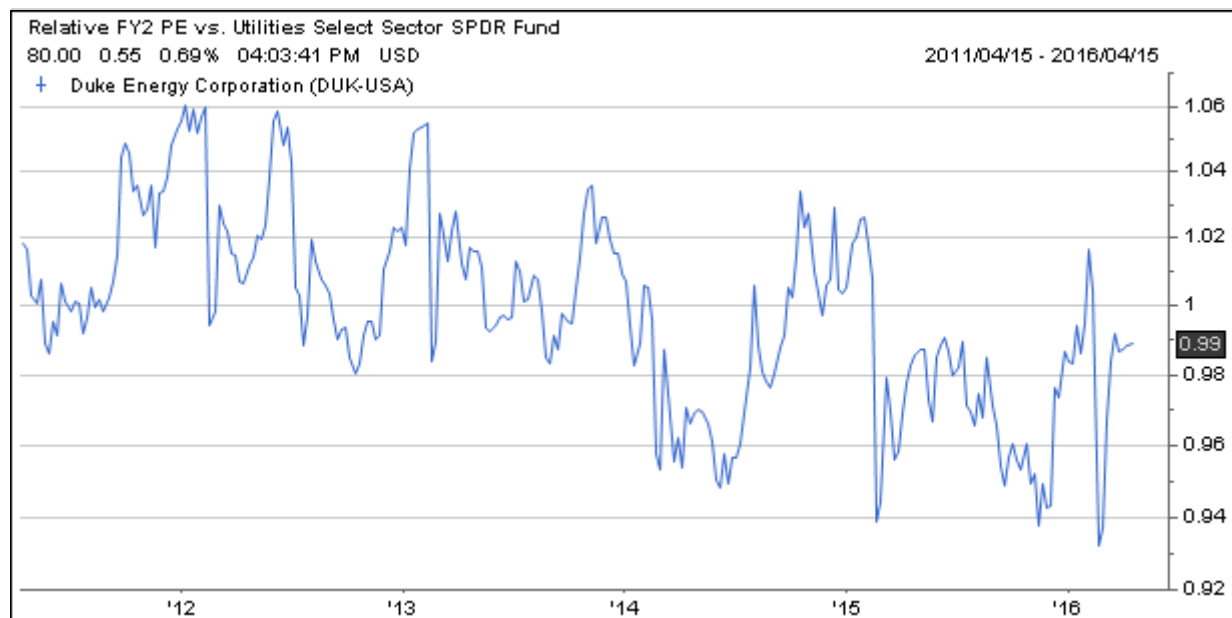
Figure 110: DUK Valuation

Duke Energy Valuation: P/E Derived on 2018 EPS					
Downside Case		Base Case		Upside Case	
2018 EPS	\$4.99	2018 EPS	\$4.99	2018 EPS	\$4.99
Minus: Lat Am Dilution	(\$0.21)	Minus: Lat Am Dilution	(\$0.21)	Minus: Lat Am Dilution	(\$0.21)
Plus: Piedmont Accretion	\$0.12	Plus: Piedmont Accretion	\$0.12	Plus: Piedmont Accretion	\$0.12
Total	\$4.90	Total	\$4.90	Total	\$4.90
P/E Multiple	15.0x	P/E Multiple	16.0x	P/E Multiple	17.0x
Premium/(Discount)	-5%	Premium/(Discount)	5%	Premium/(Discount)	10.0%
Value	\$71.00	Value	\$82.00	Value	\$93.00

Source: Company filings, FactSet, UBS estimates

**Can it be a premium story? We think so.** Duke could return to a premium, following several years of a re-rating lower given the volatility associated with *both* the South American business (between F/X and hydrology) as well as oil price sensitivity. We emphasize with a 1-year forward view that Street will increasingly shift out to 2019E/2020E EPS, which bodes relatively *better* for Duke given the in-service timing of the Atlantic Coast Pipeline among other assets as well as lumpy nature of ratecase timing in the Carolinas. Bottom line, we expect EPS growth will be trending towards the higher end of its 4-6% seemingly YoY later in the decade.

Figure 111: DUK Relative FY2 P/E Valuation



Source: FactSet

# Dynegy Inc.

We forecast Dynegy reporting 1Q15 adjusted EBITDA of **\$299Mn**, modestly ahead of the Street expectation (\$225Mn). We flag 1Q estimates should benefit substantially from continued YoY benefits from the close of the ECP & Duke portfolios, while the balance of the portfolio should continue to see YoY lower trends as both hedges and mild weather reduce expectations.

**We look for meaningful improvement YoY, ahead of Street – but we think talk of lower interest and retirements could really bolster the story**

**Figure 112: DYN 1Q16E Adj EBITDA Walk**

Dynegy (\$Mn)	1Q16E	1Q15A	YoY	Notes
Consensus EBITDA	\$225			
Adj. EBITDA UBSe	299	85		
Corp & Other	(32)	(29)	(3)	Similar trend of ~\$30Mn, slightly higher YoY
IPH	30	22	8	Implied from FY guidance
CoalCo	5	10	(5)	Capacity Uplift from MISO.
GasCo	72	82	(10)	Mild New England Weather
ECP & Duke	224	-		Transaction Closed in 2Q15

Source: Company reports, ThomsonReuters, UBS estimates

## EBITDA Estimates

We reflect the latest commodity MtM outlook, seeing estimates at the bottom-end of the range for 2016E and management lagging its \$3.9Bn 2016-2018E guidance provided at the 2015 Analyst Day.

**Figure 113: Pro-Forma Forward EBITDA Estimates for DYN**

Dynegy EBITDA Breakdown (UBSe)	2014A	2015E	2016E	2017E	2018E	2019E
Midwest	110	56	118	80	116	115
West	52	75	61	29	35	35
Northeast	187	163	141	145	164	165
Illinois Power Holdings	78	101	77	62	102	116
Duke Midwest	0	240	298	239	305	279
Energy Capital Partners	0	253	332	353	459	405
PRIDE Reloaded & Other Synergies	0	92	233	265	290	290
Consolidated G&A and Other	(80)	(130)	(130)	(130)	(130)	(130)
<b>Recurring Adjusted EBITDA</b>	<b>347</b>	<b>850</b>	<b>1,130</b>	<b>1,043</b>	<b>1,341</b>	<b>1,275</b>
<i>Previous</i>		<b>864</b>	<b>1,134</b>	<b>1,138</b>	<b>1,402</b>	<b>1,451</b>
<b>Consensus (4/14/2016)</b>	<b>\$364</b>	<b>\$880</b>	<b>\$1,107</b>	<b>\$1,179</b>	<b>\$1,257</b>	<b>\$1,296</b>
<b>Mgmt Guidance: Adj EBITDA</b>	<b>\$300-\$350</b>	<b>\$825-\$925</b>	<b>\$1.0-\$1.2Bn</b>	<b>~\$1,300</b>	<b>~\$1,300</b>	
<i>Capital Spending</i>	<b>-\$160</b>	<b>-\$285</b>				
<i>Cash Interest</i>	<b>-\$145</b>	<b>-\$425</b>				
<i>Other Cash Impacts</i>	<b>\$15</b>	<b>-\$15</b>				
<b>Free Cash Flows</b>	<b>\$10-\$60</b>	<b>\$140-\$240</b>	<b>\$200-\$400</b>	<b>~\$500</b>	<b>~\$500</b>	

Source: Company reports, USB estimates

*For additional context, please refer links to relevant recent reports below:*

[4/14/16: Painting the Path Forward](#)

[2/26/16: Bringing The Band Back Together](#)

[2/25/16: Slow Start to 2016 Dings Outlook](#)

[5/11/15: Muted Expectations](#)

[9/18/15: Capacity Auction Delivers](#)

[8/7/15: Repurchases Are Just The Right Medicine](#)

**What's New With Dynegy?:**

- **Main focus will be MISO:** More retirements and how to deal with the lower price environment. We expect management to announce retirement of *at least* its Newton plant, the most expensive plant in its MISO portfolio. We see risk to other assets in the portfolio given what we model as FCF deficits.
- **IPH restructuring:** Given the anticipated retirements, we expect discussion around how to restructure debt proactively ahead of maturity in 2017. The \$825Mn trades at less than \$300Mn in market value. A further nuance could include the contribution of *existing* assets to the IPH ring-fence for the debt following previous management statements, but it is unclear how much value that might provide (seemingly minimal).
- **Dynegy financing:** We look for discussion on when and how it intends to finance the close of its current Engie acquisition. Given the leverage and bridge structure employed, reducing financing costs would help improve the FCF profile.

Addressing IPH remains the top priority for this year

Debt is trading at ~30-40c of late, or ~\$290Mn in market value vs. \$825Mn par value

## Financials

We include our latest FCF projections below, seeing meaningful FCF (ex-Engie) as accruing in 2018.

Figure 114: DYN FCF Profile

Dynegy Free Cash Flow Analysis	2014A	2015E	2016E	2017E	2018E	2019E	2020E
Adjusted EBITDA	957	864	1,130	1,043	1,341	1,275	1,249
Less: Interest Expense	(147)	(546)	(505)	(505)	(505)	(505)	(505)
Less: Taxes	No Cash Taxes Through At Least 2018E					(156)	(146)
FCF Pre-Capex (Proxy for FFO)	810	318	625	538	836	614	598
Less: Capital Expenditures	(123)	(255)	(405)	(315)	(410)	(360)	(360)
Plus/Minus: Other	27	5	35	5	5	5	5
Free Cash Flow	714	68	255	228	431	260	243
Guidance	\$10-\$60	\$140-\$240	\$200-\$400	~\$500	~\$500		
Debt Profile (incl. ST Debt Balance)	\$7,106	\$7,289	\$7,289	\$7,289	\$7,289	\$7,289	\$7,289
Cash	\$880	\$505	\$865	\$1,136	\$1,429	\$1,656	\$1,857
Net Debt	\$6,226	\$6,784	\$6,424	\$6,153	\$5,860	\$5,633	\$5,432
Net Debt / EBITDA	6.5x	7.9x	5.7x	5.9x	4.4x	4.4x	4.3x
FFO / Gross Debt	11%	4%	9%	7%	11%	8%	8%
FCF Yield	39.2%	3.7%	14.0%	12.5%	23.7%	14.3%	13.4%

Source: UBS estimates

## What's the market value today?

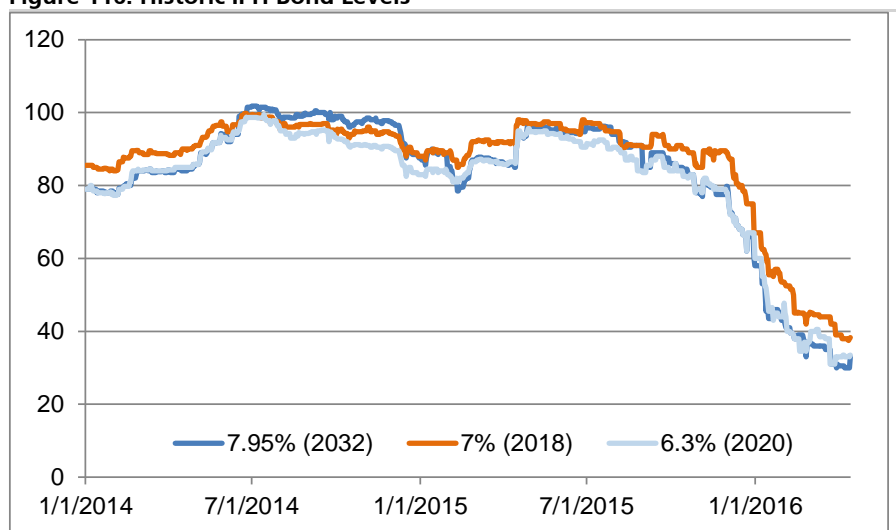
The IPH bonds imply a pricey ~\$125/kW for the remaining (2) coal plants assuming the Newton plant is retired. We would not expect management to offer to take in the structure at the current valuation, seeing limited value, particularly without the marketing enterprise behind DYN.

Figure 115: FMV of IPH Bonds (\$Mn)

Market Cap of IPH Bonds	
Notes	Value
2032	90.8
2018	114.8
2020	83.8
	289.3

Source: FactSet

**Figure 116: Historic IPH Bond Levels**



Source: FactSet

While we do not see value today in the segment even at its \$290Mn valuation of late, we think management might consider offering lenders a deal to exchange their debt for either parent obligations or tender for cash at a discount to their existing value. We note the debt has few alternatives on a standalone basis, with both remaining assets operating at seemingly breakeven FCF levels (at best).

**Figure 117: IPH Debt Summary**

As of 9/30/15 (Except Current Yield)	Maturity (yr)	Book Yield	Current Yield	2015	2016	2017	2018	2019	2020+
<b>Illinois Power Generating Company (GenCo)</b>									
Senior Notes F	2032	7.95%	24.09%						275
Senior Notes H	2018	7.00%	18.30%				300		
Senior Notes I	2020	6.30%	18.81%						250
<b>Total GenCo</b>		<b>825</b>		-	-	-	<b>300</b>	-	<b>525</b>

Source: FactSet

### An IPH deal could require rewrite of existing IL emissions requirements

We emphasize retirement and subsequent folding of the remaining IPH assets into the Dynegy portfolio could well trigger a review of the existing Illinois Multi-Pollutant Standards (MPS) impacting IPH portfolio. Notably, without plans to complete the scrubber at Newton, we see risk around compliance at other plants which were intended to be covered under a 'portfolio' approach. The question remains whether other plants recently acquired including the Kincaid plant, scrubbed already, would be allowed to enter the compliance bubble for SO<sub>2</sub> targets across the entire Illinois fleet. Expect some discussion before the Illinois Pollution Control Board (PCB) in coming months. One possible avenue could include unit de-rates amidst efforts to limit output from higher SO<sub>2</sub> plants. As a reminder, the company already employs lower-sulfur PRB coal to achieve its targets.

## How about the allocated costs to IPH?

With substantial focus on NRG's allocated costs to GenOn, allocated costs to the overall IPH portfolio is presently ~\$40 Mn, and poised to go lower upon close of the Engie deal. With ~3GW, this implies north of \$10/kW-yr of SG&A; this is similar to the GenOn Portfolio with \$193Mn across the full 17.8GW portfolio. We look for retirements at both subsidiaries to reduce the allocated costs. We note many in the sector continue to point to these costs as potentially too high, but the question remains whether management can extract comparable value under a more streamlined 'loan-to-own' scenario for private equity. With limited market transparency in MISO, this argument would appear particularly challenged for this segment. We suspect a much stronger case for the GenOn portfolio will be made.

These values are not significantly different on \$/kW basis from NRG's GenOn Subsidiary

Figure 118: Dynegy's IPH Assets

Asset	Capacity	Fuel	RTO	Interconnected
<b>Illinois Power Holdings (IPH)</b>				
Coffeen	915	Coal	MISO	Ameren IL
Joppa	802	Coal	MISO	Ameren IL
Joppa CT	221	Gas	MISO	Ameren IL
Newton	1,230	Coal	MISO	Ameren IL
<b>Total IPH ex. GenCo</b>	<b>3,168</b>			
<b>Illinois Power Generation Company (GenCo)</b>				
Duck Creek	425	Coal	MISO	Ameren IL
E.D. Edwards	585	Coal	MISO	Ameren IL
<b>Total GenCo</b>	<b>1,010</b>			
<b>Total IPH including GenCo</b>	<b>4,178</b>			

Source: Company filings

## Other Key Portfolio Issues

### Looking hard at California still to divest

Management continues to evaluate options around a contemplated divestment of its West coast portfolio. We see the bulk of the value as accruing to the portfolio via its Moss Landing CCGT, with its remaining assets (Morro, Oakland, and Moss 6&7 as primarily real estate/salvage value). We expect Moss 6&7 to be retired at year-end at the conclusion of its existing capacity contract (with just one year left on its operating life due to Once-Through-Cooling [OTC] limitations anyways).

It is unclear given the substantial additional cost from PG&E's pending GT&S ratecase (adding nearly ~\$1/MMBtu up to \$1.35/MMBtu for delivery on the PG&E gas LDC to the plant). The uptick in rates could practically eliminate all value of the plant as we perceive relatively limited dispatch should the proposed rate structure be adopted (with the ~\$200 Mn NPV swing in value potentially equal to the plant overall value when applying value of \$100-200/kW to the operating business and marginal value for the three legacy peakers). *Separately we continue to see the potential for a well-above inflation rate increase proposed on customers as a key risk to PG&E.* Status quo, we see California as worth ~\$1/sh to the overall value of DYN.

**Figure 119: California Portfolio Potential Value**

Dynergy California Portfolio Potential Transaction Value						
Asset	Location	Fuel	Dispatch	MW	\$/kW	Value (\$Mn)
Moss Landing						
Units 1-2	Monterey County, CA	Gas CCGT	Intermediate	1,020	150	\$153
Units 6-7	Monterey County, CA	Gas	Peaking	1,509	-	-
Oakland	Oakland, CA	Oil	Peaking	165	30	5
Morro Bay*	Morrow Bay, CA	N/A	N/A	650	8	5
* Transmission Capacity		<b>Total</b>		<b>2,694</b>		<b>\$163</b>
		<b>Total per Sh</b>				<b>\$1.08</b>
<i>Estimated Rate of Delivered Gas Increase Potential Under GTS Case: \$1/Mmbtu</i>					<b>NPV</b>	<b>~\$200Mn</b>

Source: UBS estimates

### Extracting more value: asset sales possible

DYN appears poised to divest additional assets in effort to continue to deleverage and re-allocate away from markets that appear robust.

- **New York Selldown?** Notably management sees opportunity around its Independence 1.2GW CCGT asset with the plant benefitting from atypically high spark spreads in this market due to the access to cheap gas. We perceive risk to the sparks in the future as cheaper gas eventually flows into the state and pushes down prices. Further, with the longer-term outlook poised to see implementation of a 50% RPS in the state – and the bulk of renewables anticipated upstate – management appears to be navigating itself early out of this market. Lastly, with just one single asset in the state, we are not surprised DYN continues to ‘simplify’ the story, particularly amidst the strong capacity and energy prospects in the medium term with threatened nuclear retirements. We expect proceeds from this asset could exceed \$600 Mn.
- **What else? PJM peakers.** We believe several could be on the block too given as management appears keen to capitalize on more robust capacity and spark spreads of late. While unclear precisely which units, we generally believe the PJM market is approaching a ‘top’ of its respective cycle. While it would appear strategically challenging to sell-down gas assets amidst its efforts to reposition the portfolio, it would appear more consistent that it is resulting in additional gas purchases, effectively replacing its portfolio at better value elsewhere.

**Similar to California, management has stated that maintaining a regulatory presence in a state required a portfolio to justify the cost and management effort**

### What to do with cash? Possibly buy down the Engie stake

Management would ideally like to own the full Engie portfolio. While ECP only has a put on its 35% of the portfolio four years down the line, the company already seems keen to collapse the entire structure. That said, other options remain on the table as well for cash deployment; we think any deployment would evaluate the state of the market in ~2017 once any sales are executed.

### Peaker Permits: Getting More Runtime

Among the other emerging trends we perceive in the northeast amidst cheap gas prices are peakers running as mid-merit units given their advantaged dispatch economics vs. coal plants. In particular, we understand at least two of the acquired plants under the Engie portfolio located adjacent to pipes with access to cheaper Marcellus-sourced gas. We emphasize these units are operating at maximum

outputs (~40%) limited principally by their environmental permits. We suspect this may prompt DYN among others to petition to expand these permits to enable their peaking facilities to operate more. Given the meaningful retirement of coal plants anticipated, we believe the added dispatch will not prove too problematic to maintain local air quality, particularly with the plants likely displacing coal output.

### Will DYN be able to finance its Engie deal? Yes, and we believe on its own

We look for management to finance the deal without the use of ECP's 11% PIK Bridge facility. The \$400Mn note had been a core risk to deal execution as it could automatically convert to equity, structurally making the transaction dilutive to Dynegy. We see the improvement in credit markets of late as disproportionately constructive to the company, implying its meaningful forthcoming financing on the \$1.85Bn of secured debt and ~\$400 Mn of likely unsecured notes will likely be issued (the exact mix is still up in the air). We would see execution of the financing plan under today's market conditions as a constructive datapoint.

**Figure 120: Near-term value driven by terms of upcoming Engie financing**

Dynegy/ECP Transaction Capital Structure			
Company	Financing (MM)	Description	
Energy Capital Partners Equity	\$367	Energy Capital Partners owns 35% of the Joint Venture	
DYN Piece:			
Proceeds from Stock Sale to ECP	\$150	ECP purchased \$150 MM of DYN common stock at \$10.94/share	
Forward PJM Capacity Sale	\$203	Liquidity generated via sale of Planning Year 2017/2018 & 2018/2019 PJM	
Existing DYN Liquidity	\$330	Cash on hand plus potential revolver borrowings (Excludes \$90Mn for transaction fees + working capital)	
Total Dynegy Equity	\$683	Total equity contribution from ECP and DYN is \$1,050 MM	
Secured Debt	\$1,850	Non-recourse secured debt incurred at the JV level. Indicative pricing is L+525bp with flex to L+800bp. OID indicative at 98.	
ECP Bridge Loan	\$400	11% Interest with PIK option. Convertible to equity at 1.5x after twelve months. 4Yr Maturity.	
Total Purchase Price	\$3,300	Excludes transaction fees and initial working capital	
Implied Interest Calculations			
	Debt Amount	Interest Rate	Interest Expense
Secured Debt	\$1,850	6.8%	\$126
ECP Bridge Loan	\$400	11.0%	\$44
Total Implied Interest Expense			\$170
Guidance			
Secured Debt Sensitivity 100bp = \$18.5Mn			

Source: Company reports and USB estimates

### How to handle out-of-the-money coal? Simply don't

We see little palatability for management to continue to operate assets that generate negative FCF; specifically, this includes its coal portfolio. Following years of distress in the power markets, we perceive an accelerated retirement. Further, we think this mantra would leave little latitude to maintain the Coletto Coal plant in Texas; thus we believe DYN might prove among the first coal operators to shut coal in the state. Should this happen, we think it would likely be the start of a trend but perhaps not immediately.

## Valuation: Maintaining \$21 Price Target

Our valuation continues to be based on a 2018E sum-of-the-parts methodology. The focus will be on the IPH subsidiary and to what extent management could provide value to bondholders for any forthcoming exchange to execute on a deal. For example, market value of debt against the *total* IPH equity would imply ~\$1/sh without adjusting for assets *not* in the ring-fence).

**Figure 121: Maintain Dynegy Valuation: The Engie Mini-Model Uplift is Included in our \$21 Price Target**

Dynegy Inc - 2018E	EBITDA	EV / EBITDA Multiples			Low	Base	High
		Low	Base	High			
Base IPP Multiple =			7.0x				
Legacy Dynegy	315	4.0x	6.0x	7.0x	\$1,260	\$1,891	\$2,206
Illinois Power Holdings (IPH)	102	4.0x	5.0x	6.0x	\$407	\$509	\$611
Duke Midwest	305	6.0x	7.0x	8.0x	\$1,827	\$2,132	\$2,436
EquiPower (~ISO-NE Portfolio)	459	6.0x	7.0x	8.0x	\$2,757	\$3,216	\$3,676
Less: West Peaking	(18)	5.0x	6.0x	7.0x	(\$91)	(\$109)	(\$127)
Synergies, Corp. Overhead, & Other	160	5.0x	6.0x	7.0x	\$800	\$960	\$1,120
Engie	538	6.0x	7.0x	8.0x	\$3,228	\$3,766	\$4,304
<b>Total Unregulated EV</b>	<b>1,879</b>	<b>5.4x</b>	<b>6.6x</b>	<b>7.7x</b>	<b>\$10,189</b>	<b>\$12,365</b>	<b>\$14,462</b>
<b>Net Debt (12/31/15)</b>							
Dynegy Inc.					\$6,380	\$6,380	\$6,380
Illinois Power Holdings (IPH)					\$825	\$825	\$825
Engie-Related Financing					\$1,850	\$2,870	\$2,870
Plus: NPV of West Peaking					(\$25)	(\$45)	(\$50)
Cash and Equivalents					(\$253)	(\$505)	(\$880)
<b>Total Net Debt</b>					<b>\$8,778</b>	<b>\$9,525</b>	<b>\$9,145</b>
Net Debt / Adjusted EBITDA					4.9x	5.29x	5.1x
Removing Net Equity Drag of IPH					\$418	\$316	\$214
<b>Total Equity Value</b>					<b>\$1,829</b>	<b>\$3,156</b>	<b>\$5,531</b>
Implied FCF Yield					12%	7%	4%
Shares Outstanding					151	151	151
<b>Dynegy Valuation</b>					<b>\$12.00</b>	<b>\$21.00</b>	<b>\$37.00</b>
<b>Upside/(Downside)</b>					<b>-23%</b>	<b>35%</b>	<b>137%</b>
Price Target Gross EV/EBITDA Multiple					5.4x	6.6x	7.7x
Current Price Implied Gross EV/EBITDA Multiple					5.6x	6.0x	5.8x
Dilution Implied from Consolidating IPH					-\$2.77	-\$2.09	-\$1.42

DYN/ECP Engie Portfolio	EBITDA	EV / EBITDA Multiples			Low	Base	High
		Low	Base	High			
ISO-NE	216	6.0x	7.0x	8.0x	1293	1509	1724
PJM	197	6.0x	7.0x	8.0x	1181	1378	1575
ERCOT	126	6.0x	7.0x	8.0x	754	880	1005
<b>Total Unregulated EV</b>	<b>538</b>	<b>6.0x</b>	<b>7.0x</b>	<b>8.0x</b>	<b>\$3,228</b>	<b>\$3,766</b>	<b>\$4,304</b>
<b>Pro-Forma Financing</b>							
Secured Debt					(1,850)	(1,850)	(1,850)
ECP Bridge Loan					(400)	(400)	(400)
DYN Equity Sale to ECP					(150)	(150)	(150)
DYN Forward Capacity Sale					(200)	(200)	(200)
DYN Cash/Borrowing Contributed					(420)	(420)	(420)
<b>Total Debt+DYN Equity</b>					<b>(3,020)</b>	<b>(3,020)</b>	<b>(3,020)</b>
<b>Total Equity Value</b>					<b>\$208</b>	<b>\$746</b>	<b>\$1,284</b>
<b>DYN's Equity Value (65%)</b>	<b>65%</b>				<b>\$135</b>	<b>\$485</b>	<b>\$835</b>
Shares Outstanding					137	137	137
<b>Dynegy Valuation</b>					<b>\$1.00</b>	<b>\$4.00</b>	<b>\$6.00</b>

Source: Company filings, FactSet, UBS estimates

# Edison International

*We see in-line 1Q EPS at \$0.88 vs. consensus \$0.88, with a dime of higher ratebase earnings offset by a higher effective tax rate under Tax Act Memorandum Accounting (TAMA). We continue to note that there is no requirement for any further response from the ALJ regarding SONGS.*

We expect an in-line **\$0.88** for the quarter vs. \$0.88 consensus with +\$0.06 increased ratebase (including pole loading earnings) and +\$0.04 productivity and financing benefits (out of \$0.17 total projected for FY2016). We expect this to be offset by -\$0.09 of higher utility income taxes as a result of passing repairs tax benefits back to customers under TAMA. We also expect -\$0.02 higher parent expense, primarily as a result of the elimination of affordable housing tax credit income and higher financing cost at Edison Capital (with parent & other increasing to a -\$0.18 loss for FY2018E vs. -\$0.10 in 2015).

In the next table, we break down our estimate for the 2016 quarterly earnings distribution, based largely on the past distribution of EPS in years that exclude the accounting treatment for the shutdown of the San Onofre Nuclear Generating Station (SONGS).

**Outperformance could principally come from continued cost savings**

**Possible upside drivers include discussion of Edison Energy and arbitration resolution**

**We view EIX as the low-risk California play at present**

**Figure 122: EIX 2016E UBS Quarterly Estimates**

	Ex-SONGS EPS Distribution				Total
	Q1	Q2	Q3	Q4	
2009 EPS distribution	24%	24%	34%	18%	
2015 EPS distribution	22%	28%	28%	21%	
Average Ex-SONGS EPS Distribution	23%	26%	31%	20%	
UBSe 2016 Estimate Distribution					
Ratebase	0.88	1.00	1.18	0.75	3.81
Reduce ratebase for bonus depn	(0.01)	(0.01)	(0.01)	(0.01)	(0.05)
Add Pole Loading ratebase	0.02	0.02	0.03	0.02	0.09
O&M reduction	0.04	0.04	0.05	0.03	0.17
Edison Energy Group	-	-	-	-	-
Energy efficiency	-	-	-	0.05	0.05
Parent & other	(0.05)	(0.05)	(0.05)	(0.05)	(0.18)
UBSe 2016 (basic)	0.89	1.01	1.20	0.80	3.90
UBSe 2016 (diluted)	0.88	1.00	1.19	0.79	3.86
Consensus	0.88	0.97	1.25	0.77	3.88
Core Basic EPS Guidance					3.81-4.01

Source: UBS estimates, company filings, FactSet

The next table illustrates our estimates for year-over-year quarterly EPS impacts.

**Figure 123: EIX 2016E UBS Quarterly Estimates**

2016 vs 2015 Delta (diluted)	Q1	Q2	Q3	Q4	Total
2015A (diluted)	0.89	1.15	1.15	0.87	4.06
Ratebase growth (w/Pole Loading)	0.06	0.07	0.09	0.05	0.28
Productivity and financing benefits in 2016	0.04	0.04	0.05	0.03	0.17
O&M & Severance	(0.01)	0.02	0.03	(0.12)	(0.08)
Change in uncertain tax positions		(0.31)			(0.31)
Higher utility taxes under TAMA	(0.09)	-	(0.11)	(0.03)	(0.22)
Generator settlements in 2015		0.03			0.03
Property tax refund in 2015		0.01			0.01
Parent & Other	(0.02)	(0.02)	(0.02)	(0.02)	(0.08)
2016E UBSe, diluted)	0.88	1.00	1.19	0.79	3.86

Source: UBS estimates, company filings, FactSet

## Unchanged estimates

As illustrated in the table below, our unchanged 2016-2018 estimates reflect the reduced impact of bonus depreciation on ratebase as offset by increased Pole Loading capex and ratebase as well as an assumption for \$50M of electric vehicle charging station capex in 2018. Note that our EV assumption is conservative vs. the utility's ambitious plan for up to \$300M of capex based on ~30K stations (PCG had proposed a similar program which has since been pared back to only 7,500 stations after discussions with regulators).

We've also taken our 2017/18 estimates for the utility's Energy Efficiency program up a penny to \$0.04 after management took up their estimate for 2016 to \$0.05 for a second year in a row. As previewed by the company last year, parent and other costs are projected to increase to -\$0.18 (-\$0.02 higher than our previous estimate), primarily as a result of the elimination of affordable housing tax credit income and higher financing cost at Edison Capital.

**We see an upside bias to our cost savings estimates – and hence our 2016 & 2017 EPS estimates**

**Figure 124: EIX Mini-Model, UBS estimates vs. Consensus, 2014A-2018E**

EIX Mini Model	2014A	2015A	2016	2017	2018
Ratebase (midpoint) - including all adjustments below	22.4	23.3	25.1	26.7	28.9
Ratebase growth (delay \$600M transmission into 2018/19)		4.0%	7.5%	6.6%	8.1%
% FERC	22.0%	21.3%	21.5%	22.0%	22.0%
CPUC ROE	10.45%	10.45%	10.45%	10.45%	10.45%
FERC ROE buildup					
FERC Base Rate	9.30%	**	**	**	9.77%
CAISO (RTO Participation Adder)	0.50%	**	**	**	0.50%
Avg. Project Incentive Adder	0.65%	**	**	**	0.65%
FERC ROE	10.45%	10.45%	10.45%	10.45%	10.92%
Equity%	48.0%	48.0%	48.0%	48.0%	48.0%
Shares (basic)	326	326	326	326	326
Shares (diluted)	329	329	329	329	329
Ratebase EPS					
Ratebase EPS before adjustments below	3.45	3.54	3.81	4.11	4.52
Reduce ratebase for bonus depn		-	(0.05)	(0.11)	(0.14)
Add Pole Loading ratebase		0.05	0.09	0.11	0.11
Add DRP ratebase (assume \$50M for EV program in 2018)					0.01
Pole Loading - Debt & Pref		0.03			
SONGS shutdown	(0.06)				
1x Income tax benefit	0.51	0.37			
Cost savings	0.74	0.08	0.17	0.20	
Edison Energy Group			-	-	-
Energy efficiency	0.04	0.05	0.05	0.04	0.04
AFUDC benefits		0.08			
Parent & other	(0.09)	(0.10)	(0.18)	(0.18)	(0.18)
<b>Total EPS (basic)</b>	<b>4.59</b>	<b>4.10</b>	<b>3.90</b>	<b>4.17</b>	<b>4.36</b>
<b>Total EPS (diluted)</b>	<b>4.55</b>	<b>4.06</b>	<b>3.86</b>	<b>4.13</b>	<b>4.31</b>
Previous UBSe	\$ 4.55	\$ 4.06	\$ 3.86	\$ 4.13	\$ 4.31
Consensus	\$ -	\$ -	\$ 3.88	\$ 4.10	\$ 4.30
Guidance (basic shares)			3.81-4.01		

Source: UBS estimates, company filings, FactSet

*For additional context, please refer links to relevant recent reports below:*

[3/4/16 The 'How Can Utilities Be So Great Again?' Conference Deluge \(p. 27\)](#)

[2/24/16 Taking the Pole Position](#)

[11/30/15 Accounting for Tax Benefits](#)

[11/5/15 At the 1-Yard Line: A Mostly Final Ratecase Order](#)

[10/28/15 Looking Through the Transmission Delays](#)

[9/21/15 Rebasing the Power Trade](#)

[8/10/15 Less Settled, But Still Intact](#)

[8/3/15 SONGS Enters New Stanza with \\$7.6B Arbitration](#)

[6/25/15 TURNing Its Back on the SONGS Deal](#)

[6/9/15 Preparing for the California Rate Design Shift](#)

[6/5/15 Calming Concerns on California](#)

[4/29/15 Time for a Tune Up Over SONGS](#)

[2/26/15 Cutting into the 2015 Reset](#)

[1/14/15 Charging up the Utility EV Infra Opportunity](#)

[10/30/14 High Growth Story Now Fully Valued](#)

[10/15/14 3Q14 Earnings Playbook: Trading Tips for Turbulent Times](#)

[10/24/14 How Low Could Transmission ROEs Go?](#)

[8/1/14 Up, Up, and Away \(in 2014\)](#)

[3/30/14 Focused on the Core Strategy](#)

[3/24/14 Hitting the High Notes With SONGS](#)

## Expansion effort for Edison Energy Group

Management remains focused on expanding its integrated energy services platform to address the needs of commercial and industrial (C&I) customers, particularly those with multi-state operations that are underserved nationally for energy needs and new technologies. The company recently launched a C&I marketing effort.

Ultimately, management hopes to scale up to ~10% of total EIX earnings if successful

EIX has noted success in expanding its Solar C&I efforts via its SoCore platform and continues to leverage its team towards industry-wide coordination efforts for backup known as Grid Assurance. So far, SoCore now has 250 projects operating in 16 states and has expanded beyond rooftop solar to ground-mounted projects for both community solar and rural cooperatives.

To date, less than 1%-2% of the total EIX capital budget is allocated to Edison Energy and the company has acquired several small engineering and consulting companies in recent months with an eye to scaling up successful efforts, including Eneractive Solutions, Delta Energy, and Altenex. Ultimately, management hopes to scale up to ~10% of total EIX earnings if successful.

Separately, we note little success to date in its competitive transmission efforts aside several projects offered up by CAISO, so there's little to speak of thus far (EIX splits up who bids on projects between its competitive team and SCE).

# Empire District Electric Company

*EDE has made the necessary state filings but still faces a long regulatory approval path given the number of jurisdictions. Although a prior effort at M&A was unsuccessful in 2000, Algonquin has already made commitments to retain employees and we ultimately expect the transaction to close but think the ~7-month regulatory path may not be consistently smooth.*

**EDE still intends to host earnings calls at this point**

**For additional context, please refer links to relevant recent reports below:**

[2/23/16 Searching For Clues in Regulated M&A](#)

[2/10/16 Acquiring an Empire](#)

[12/13/15 Evaluating Alternatives](#)

[11/3/16 Ratecase Double Header](#)

[9/28/15 Approaching Ratecase Season](#)

[8/11/15 Show Me The Ratecase](#)

[5/11/15 Stuck in a Growth Quagmire](#)

[2/10/15 Structurally Lagging?](#)

## **What are the pivotal questions for EDE?**

### **What is the status of the pending Algonquin transaction?**

- EDE management mentioned all state filings relating to the Algonquin transaction have been submitted as of the end of March. EDE has guided to a 1Q16 close while Algonquin has been more precise in stating it expects a January 2017 close. With respect to financing the \$2.4B deal, Algonquin has secured C\$1.15B convertible debentures, is assuming \$900M in debt and only has to complete the \$600M private placement.
- **EDE previous attempt aborted in 2000; four state approvals required.** EDE's prior acquisition was in 1999 by Utilicorp (present day GXP), which offered \$29.50/sh (+39% at time); the deal was ultimately terminated after a negative PD from an ALJ in AR and rejection of implementation plan by MO in late 2000. While rates in AR have recently been shifted to coincide with rate-making in MO, we emphasize a 'change of control' across all four states would still seemingly require proof of net benefits. With the city of Joplin struck in recent years by an F5 tornado, we think potential departure of the HQ from the city would likely be closely considered by the MO PSC.

### **What is the latest in the pending Missouri Ratecase?**

- **PSC Staff recommends +\$21 rate increase vs. +\$33.4Mn request:** On March 25<sup>th</sup> the PSC Staff recommended a \$21M rate increase and a 9.75% ROE on \$1.2B ratebase. Empire's current ratecase proceeding was filed in mid-October to recover costs associated with converting the Riverton CC 12 generation plant to a combined-cycle unit (est. cost of \$165-175M). EDE supports a \$33.4Mn electric rate increase premised upon a 9.90% ROE and a ratebase valued at \$1.37B.

Figure 125: 2016 EDE Ratecase Filing

Rate Case Revenue Requirement Drivers: ER-2016-0023		
Requested Items	Revenue Req.	% of Total
Riverton Unit 12 CC Conversion	27.4	82.0%
Asbury True-Up	2.1	6.3%
Effect of Depreciation Study	-1.0	-3.0%
ROE / Capital Structure	-3.2	-9.6%
Other Normal Plant Additions	6.0	18.0%
Administrative Costs	2.1	6.3%
<b>Total Increase Request</b>	<b>33.4</b>	
<b>9.9% Requested RoE</b>		

Source: Company filings

Figure 126: 2014 EDE Ratecase Filing

Rate Case Revenue Requirement Drivers: ER-2014-0351		
Requested Items	Revenue Req.	% of Total
Asbury Environmental	19.8	81.5%
Property Taxes	2.9	11.9%
RTO Transmission Charges	1.0	4.1%
Maintenance Contract	3.9	16.0%
Other (SPP and Int. Exp Savings)	-3.3	-13.6%
<b>Total Increase Request</b>	<b>24.3</b>	
<b>Approved Settlement Increase</b>	<b>17.1</b>	
<b>10.15% Requested RoE</b>		

Source: Company filings

## What is the true potential of ratebase growth?

- Algonquin indicates that EDE ratebase growth could accelerate above 4% but timing is likely longer-dated: In Algonquin's March 2015 presentation, the company disclosed their outlook for ratebase growth. Among the four main opportunity areas are:

- Active pursuit of coal replacement/displacement with new ratebase renewables
- Replacement of energy sourced through PPA with ratebased generation
- Further conversion of coal assets to natural gas co-generation
- Joint IT infrastructure investments

Aside from the fourth item relating to IT spending we view the opportunity areas as longer-dated and beyond the scope of the current investment horizon. For example the first PPA to expire is in 2025.

We agree with AQN that there are ratebase growth opportunities related to environmental policies but do not expect any material changes to the capex forecast before 2020

## Lowering EPS estimates for merger costs

EDE expects to incur approximately \$15-17Mn million with half payable in 2016. As a result, management guided full-year 2016 EPS down ~\$0.10.

Figure 127: EDE EPS Estimates

EDE EPS Estimates	2014A	2015E	2016E	2017E	2018E
UBS Estimates	\$1.55	\$1.29	\$1.33	\$1.42	\$1.56
Guidance			\$1.26-\$1.44		
Prior estimates		\$1.29	\$1.45	\$1.52	\$1.58
Consensus estimates		\$1.29	\$1.48	\$1.58	\$1.70
Implied Earned ROE					
Using Ratebase Math	8.1%	6.3%	6.2%	6.5%	7.2%
Using GAAP Average	8.8%	7.1%	7.2%	7.5%	8.1%

Source: Company filings, FactSet, UBS estimates

EDE updated their expectations for '16 earnings in late February to reflect the full impact of transaction costs associated with the EDE-AQN merger

## Valuation: Maintain price target

Valuation is based on the full takeout price. Our upside and base cases assume 100% probability of merger success, and our downside case assumes a -5% discount for the utility (\$27/sh). Given past M&A complications for EDE, we believe shares could trade wide of the deal price through much of the regulatory process.

We still do not see the standalone business as being worthy of a significant premium

# Entergy Corp.

We expect management to report 1Q adjusted EPS of **\$1.14**, slightly behind the Street (\$1.26), as management already guided down quarterly expectations on the 4Q call in February that weak weather was impacting earnings. We expect few updates ahead of its June Analyst Day. That said, even the Analyst Day promises only modest updates, likely reflecting added regulated spend more than any overarching shift in corporate strategy. While management has clearly left open the possibility for a tax uplift in 2016 (limiting earnings quality and comps in the year), it emphasized this will likely be a factor for later in the year rather than 1Q.

**1Q results could be a bit weak, but focus will be around what lies ahead at the Analyst Day**

**Figure 128: ET 1Q16E Earnings Walk**

Entergy Corp. Earnings Walk	EPS
<b>1Q15A EPS</b>	<b>\$1.68</b>
<b>Entergy Wholesale Commodities (EWC)</b>	
Refueling Days (~Comparable YoY).. IP2 vs. IP3 Outage	-
Outage Days	-
RISEC	0.02
O&M - EWC: Mostly Pension & OPEB	0.03
Decommissioning - Lumpiness @ VY	(0.01)
Other Income	(0.03)
Other	0.02
MtM on Hedges for 4Q YoY	(0.27)
Palisades Benefits	0.04
<b>Utility</b>	
Weather vs. Normal 1Q16 (Lower HDD given Mild 1Q)	(0.15)
Weather vs. 1Q15 (Reversal)	(0.08)
Tax Items	(0.13)
Sales (1.9% Growth assumption)	0.03
AR Rate case + small TX DCRF	0.18
Depreciation	(0.06)
Non-Fuel O&M	0.05
Parent & Other	(0.03)
Income Taxes	(0.15)
<b>1Q16E Adjusted EPS</b>	<b>\$1.14</b>
<b>1Q16 Consensus</b>	<b>\$1.26</b>
<b>2016 EPS Guidance Range</b>	<b>4.95-5.75</b>
<b>2015 Consensus</b>	<b>\$5.87</b>

Source: Company filings, FactSet, UBS estimates

## What will management report at its Analyst Day?

With management poised to provide a more meaningful update in subsequent weeks after 1Q results at its June 9 Analyst Day, we expect any meaningful updates to its EPS growth expectations to be reserved at this time.

- **Smart meter led growth:** We look for management to elaborate on future investment in both AML and other distribution upgrades.
- **Transmission is our focus too:** We continue to perceive eventual integration spend tied to MISO as a longer-dated eventuality. Among utility peers offering transmission-led growth, we see the ability for Entergy to ramp spend to more thoroughly integrate itself into MISO dispatch has real merit. We attribute some of the ambiguity in this opportunity to ongoing seams issues w/ SPP and MISO.

- **Louisiana generic dockets:** We flag much scrutiny among investors in the two generic dockets created in Louisiana around the treatment of consolidated taxes as well as treatment of holding company leverage. With ETR not paying any meaningful holding-company level taxes as well as employing meaningful holding company leverage both of these appear quite relevant. That said, the dockets were opened on the heels of the recently approved acquisition of Cleco by Macquarie rather than for any specific evaluation of Entergy.
- **Double leveraging and tax issue dockets:** Commissioner Scott Angelle directed the PSC Staff to open the first docket in order to investigate double leveraging issues for Louisiana's utility companies. The Commissioner suggests the usage of double leveraging to fund a utility's capital structure should not result in the inclusion of the costs associated with double leveraging in the rates paid by customers. The second docket, also initiated by Commissioner Angelle, directs Staff to investigate tax structure issues for the same utilities. This docket argues the utility company should not be able to include in retail rates the state or federal taxes that exceed the utility's share of the actual taxes that will be paid to taxing authorities. The key question around looking through utility tax rates back to the holding company is whether it is *other* businesses that drive this reduction (eg – tax losses from the nuclear business for instance).
- **Louisiana Renewables: RFP Issued for 200 MWs:** Entergy Services stated its intent to file a Request for Proposals (RFP) for Renewable Resources on behalf of Entergy Louisiana (ELL). ELL is seeking responses from interested parties to add up to 200 MW of renewable resources with the goal of providing "fuel diversity and other benefits to customers." The company identified a need to add approximately 2,100 MW of capacity by 2020 to be able to meet the forecasted load growth and address unit deactivations. Bidders will be permitted to submit proposals for PPAs with a maximum term of 20 years and a start date as early as June 1, 2018. The technologies being requested include Biomass Energy, Hydrokinetic, Solar Photovoltaic, Solar Thermal, and Wind.
  - This marks among the first large-scale utility RFPs for renewables in the state. It is unclear if the utilities will participate in the bid; management has previously submitted self-build options in many of its prior RFPs for gas and coal plants. We expect this to be addressed either with 1Q or at its Analyst Day.
- **Pilgrim: Opting to keep it open through 2019:** While management was faced with a decision whether to buy back its ISO-NE obligation between 2017-2019 or retire the plant early (next Spring's refuelling outage), it appears management was able unable to source adequate capacity at a reasonable price to offset this plant. Given its location in the already constrained SEMA region, the price paid would clearly have been a meaningful negative FCF through the forecast period.
- **Can a deal be cut in New York: Trade Fitzpatrick for Indian Point?** This remains among the principle potential upsides to shares, seeing an opportunity to both keep the Fitzpatrick nuclear unit around under a cash-breakeven or positive arrangement—in exchange for arriving at a deal with the state around the fate of its dual-unit Indian Point plant. Given prospects for cheaper gas coming into the region from new Marcellus-sourced pipelines, we see obtaining greater clarity here as a key opportunity. The creation of a Zero

#### Louisiana Dockets:

**Double leverage: R-34026**

**Tax structure: R-34029**

**We note the timing of the dockets coincides with the approval of the sale of Cleco to foreign owner Macquarie Infrastructure**

Emission Credit (ZEC) market remains a key focus for the NY PSC into the ~June timeframe.

- **Early buy out of Palisades PPA makes financial sense as avoid continued embrittlement focus:** Entergy Nuclear Operation's Palisades plant is currently being examined for embrittlement. Third-party organizations have expressed concerns that the Palisades reactor is at risk of a thermal shock event, where cooling the reactor could cause a breach. We maintain our position with regards to a potential shutdown of the facility, as written in a [previous note](#). We believe the plant will be retired at the conclusion of its existing PPA in 2022. **Given the above market nature of the contract with CMS, we would not be surprised to see an early retirement either, offering both sides value in reducing costs to consumers (and potentially enabling an accelerated opportunity for CMS to build a new gas plant to replace the capacity) as well as a further datapoint in the ETR strategy to its merchant (and contracted) nuclear business.** The existing contract provides little value to ETR despite its high cost the contrast has hovered near ~\$50/MWh. *The most recent update from the NRC was in late-2015 when the agency denied a hearing into whether or not the nuclear reactor could crack from exposure to radiation.*
- **ETR subs close Union Power Station deal:** During the first week of March, ETR's subsidiaries closed a transaction to acquire the 1,980 MW Union Power Station in Arkansas. The plant operates four CCGT units at 495 MWs each. The plant was purchased for approximately \$948 million; ETR stated this price tag is about half of what it would cost to build a "comparable new CCGT facility." This was the latest example of the company buying an existing asset to 'ratebase it' at a discount to new costs of building such an asset. We continue to see further such opportunities exist.

As explained at the EEI conference (page 10 of the presentation), ETR expects to require over 3.3 GW of new generating capacity as well as several major transmission upgrades to enable a renewal of industrial growth in its territory over the next six to eight years. Approximately 12.7 GW of ETR's fleet are more than 30 years old, further necessitating a modernization. The Union plant is actually considered "additional resources" in the supply plan and is incremental (not part of) this 3.3 GW.

Over the past 10 years, ETR has purchased about 2 GW through seven plants, including most recently Hot Springs and Hinds (bought in Nov 2012). The Union acquisition was not accomplished through the RFP process, although there is an RFP outstanding in Arkansas. ETR still sees the need for an 800-MW Amite South CCGT that is currently the subject of an RFP with a May 2015 decision (includes a self-build option at Little Gypsy).

**Figure 129: Union Plant Ratebase Math**

	Units	Purch Px (\$M)	ROE	Eq Ratio	NI
ETR Ark	1	\$237	9.50%	28.64%	\$ 6.4
ETR GSL	2	\$474	9.95%	51.72%	\$ 24.4
ETR TX	1	\$237	9.80%	48.59%	\$ 11.3
Net Income		\$948			\$ 42.1
Shares					180.5
EPS					\$ 0.23

Source: Company filings, UBS estimates

## Feedback from our CMS/ETR Note: [Taking a DIG at Palisades](#)

We took an updated look at our Palisades mini-model post client feedback to account for more specific generation data, implied higher PPAs from ETR's 10-K, and cost data sourced from SNL Financial. Our conclusion remains unchanged with ~\$700Mn of NPV potential customer savings under our revised model. Further, we have shifted our thoughts around ETR's value proposition and considered *marginal cash costs rather than fully loaded costs in doing our analysis*; we arrive at *lost* ~\$280NPV to ETR for accelerated retirement of Palisades. We continue to see mutually beneficial interest in Palisades decommissioning in 2017.

*Our updated thoughts around Palisades economics are included below.*

**Figure 130: Palisades Benefits to ETR and Customers**

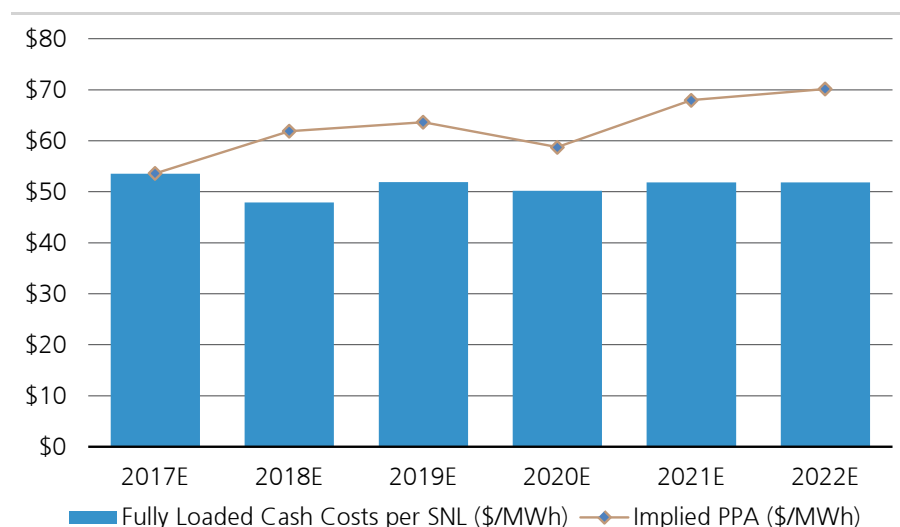
Palisades I/S	2015A	2016E	2017E	2018E	2019E	2020E	2021E	2022E
Capacity (MW)	798	798	798	798	798	798	798	798
Generation (GWh)	6,319	4,908	6,567	5,866	5,876	6,587	5,886	5,886
Capacity Factor (%)	88%	70%	94%	84%	84%	94%	84%	84%
[Original] Contract Price (\$/MWh) \$ 51.0 \$ 52.5 \$ 54.0 \$ 55.5 \$ 57.0 \$ 58.5 \$ 60.0 \$ 60.0								
Contract Revenues (\$ Mn) per CMS 10K (†)	\$ 342.0	\$ 352.0	\$ 363.0	\$ 374.0	\$ 387.0	\$ 400.0	\$ 413.0	
Implied PPA (\$/MWh)			53.60	61.88	63.65	58.75	67.96	70.17
Disclosed PPA (\$/MWh)							\$ 61.5	
Total Fuel + O&M per SNL (\$/MWh)			\$ 36	\$ 36	\$ 36	\$ 36	\$ 36	\$ 36
Total Fuel + O&M per SNL (\$ Mn)			\$ 236	\$ 211	\$ 212	\$ 237	\$ 212	\$ 212
Capex ('19+ is 3-year Avg)	\$ 95	\$ 115	\$ 70	\$ 93	\$ 93	\$ 93	\$ 93	\$ 93
Fully Loaded (\$ Mn)		\$ 351	\$ 281	\$ 305	\$ 330	\$ 305	\$ 305	\$ 305
Fully Loaded Cash Costs per SNL (\$/MWh)			53.51	47.93	51.88	50.17	51.86	51.86
<u>Replacement Price from CMS' DIG Power Plant</u>								
Market Price Proxy in MISO (ATC for Indy Hub) \$/MWh		\$ 28	\$ 29	\$ 30	\$ 31	\$ 32	\$ 33	
Capacity Prices (\$/kW-mo), DIG gets paid ~today		\$ 3.0	\$ 3.2	\$ 3.4	\$ 3.6	\$ 3.8	\$ 4.0	
Capacity Prices (\$ Mn)		\$ 29	\$ 31	\$ 33	\$ 34	\$ 36	\$ 38	
Cash Value to ETR			\$ 0.59	\$ 82	\$ 69	\$ 57	\$ 95	\$ 108
<b>NPV to ETR @ 10% (\$ Mn)</b>			<b>\$ 278</b>					
		\$ -						
<u>Savings</u>								
Annualized Savings (\$ Mn)		\$ 139	\$ 160	\$ 165	\$ 149	\$ 177	\$ 182	
<b>NPV @ 10% (Potential customer savings)</b>			<b>\$ 697</b>					
<b>NPV (Consumers) - NPV (ETR)</b>			<b>\$ 418</b>					

Source: UBS estimates

## Shifting to Cash Costs to Run, Rather than Corporate Allocations

Our initial Palisades mini-model examined the plant on a corporate-level basis (allocating ETR corporate costs proportionally), but we present costs now consistent with a plant-level decision focused on seemingly marginal cost only. How do we arrive at marginal costs? We leverage SNL's quoted \$/MWh costs as well as embed the disclosed capex figures to arrive at all-in figure, that is modestly above ETR's disclosure to account for its single-unit nature. We flag the ~\$50/MWh cash costs are modestly above the industry average of ~\$45/MWh for a single unit, seemingly due to a higher capex profile; see our wider industry discussion on nuclear costs here [Getting Nuclear on Nuclear Costs](#). We have shifted our methodology to incorporate cash costs only, which yields ~\$280M of NPV, showing modestly positive FCF and EBITDA per annum. This implies even improving PPA rates are only slightly better than marginal cost of production at Palisades.

**Figure 131: Cash Costs vs. PPA**



Source: UBS estimates

### Decommissioning Costs – What’s Left

As of most recent filing (2014), Palisades decom trust was fully funded with \$384Mn FV versus \$380Mn of current trust liability. While an early retirement would reduce the accrual period through which funds could grow to meet the projected liability, the company could always employ a SAFSTOR solution to delay decommissioning activities up to 60 years after plant shutdown. While accelerating the liability forward 5 years is a consideration, we don’t see it as a meaningful one.

### Looking at the Implied and Actual PPA Prices Disclosed

While early-year actual payments to ETR for Palisades appear to be substantially lower than out years, the implied escalator and PPAs are shown below and suggest 3%+ annual escalator (albeit with different capacity factors given the refuel cycle).

**Figure 132: CMS Projected Obligations, Projected Generation per NRC and Implied PPA Price**

	Actual Payments			Company Ests						
	2013	2014	2015	2016	2017	2018	2019	2020	Post 2020	Total Remaining
\$M Obligations	\$338	\$302	\$352	\$342	\$352	\$363	\$374	\$387	\$509	\$2,327
Implied Escalator					2.9%	3.1%	3.0%	3.5%		
Net Generation (GWh)	6,042	5,823	6,319	4,908	6,567	5,866	5,876	6,587		
<b>Implied PPA (\$/MWh)</b>	<b>\$55.9</b>	<b>\$51.9</b>	<b>\$55.7</b>	<b>\$69.7</b>	<b>\$53.6</b>	<b>\$61.9</b>	<b>\$63.6</b>	<b>\$58.8</b>		
Previous PPA (NRC Filing)	\$49.0	\$50.0	\$51.0	\$52.5	\$54.0	\$55.5	\$57.0	\$58.5	\$60.0	

Source: NRC filing, CMS

### Is it about jobs? Yes, this seems to be the real sticking point

Further client pushback centered around the 600 full-time jobs tied to the Palisades plant; this remains a key source of potential pushback as we see the current administration as keenly focused on job creation and maintenance. We flag refuelling events bring 1,000 temporary jobs to the region. Construction in place of Palisades would create several hundred construction jobs over 2-3 years in addition to ongoing operator jobs, albeit with substantially fewer permanent roles at the compact gas plant replacement. While a nuclear plant may employ more

people on balance, we *still* believe the economic argument around customer benefits to CMS rate payers are largely more compelling.

### Big Rock Could be Another Angle

The decommissioned nuclear plant, Big Rock Point (in Northern MI), could provide further leverage in favor of an accelerated retirement at Palisades, in our view. We believe ongoing legal disputes related to waste storage could incentivize public support so that Big Rock could be dealt with simultaneously; the sale from Consumers Energy to Entergy also included a \$30Mn payment to eventually address this spent fuel site.

## Earnings Projections

Below we show our latest earnings estimates, reflecting the latest commodities. We note our consolidated Utility & Parent estimates remain on the lower half of management's guidance through the three year view.

**Figure 133: Entergy EPS Estimates**

EPS by Segment	2014A	2015A	2016E	2017E	2018E	2019E
Regulated Utility	4.64	6.12	5.53	5.90	6.10	6.42
EWC/Nuclear	2.19	1.03	0.89	0.19	0.08	(0.11)
Other	(1.00)	(1.15)	(1.30)	(1.25)	(1.26)	(1.32)
<b>Consolidated</b>	<b>5.83</b>	<b>6.00</b>	<b>5.12</b>	<b>4.84</b>	<b>4.92</b>	<b>4.98</b>
<i>Prior UBSe</i>	<i>5.83</i>	<i>6.00</i>	<i>5.12</i>	<i>4.96</i>	<i>4.97</i>	<i>5.13</i>
Consensus (4/18/16)		5.83	5.17	5.23	5.15	5.40
Guidance (4Q15)		5.50-6.10	4.95-5.75			
Utility Parent & Other		3.35	4.20-4.50	4.50-4.90	4.70-5.10	
UBSe		4.97	4.23	4.65	4.84	5.09
Regulated Payout %		67%	80%	76%	76%	75%

Source: Company sources, UBS estimates, FactSet

## Reflecting the Latest Forwards

We include our latest estimates relative to guidance below. We note our estimates continue to reflect both the RISEC CCGT (recently sold) and Pilgrim.

**Figure 134: EWC MtM Adj EBITDA Projections – Pro-forma for latest sale/closure**

EWC GenCo Est (\$Mn)	2014A	2015A	2016E	2017E	2018E
EWC UBSe Adjusted EBITDA	919	520	522	362	322
Retiring Assets		62	105	130	60
Core		453	350	380	340
EWC Guidance - 4Q15 (12/31/15)		515	455	510	400
EWC Guidance - 3Q15 (9/30/15)		530	550	520	370
EWC Guidance - 2Q15 (6/30/15)		490	480	470	
EWC Guidance - 1Q15 (3/31/15)		520	520	540	
RISEC UBSe Adjusted EBITDA		73	48	61	82
Pilgrim UBSe Adjusted EBITDA		62	62	52	70
<b>Net UBSe Adjusted EBITDA</b>		<b>385</b>	<b>413</b>	<b>248</b>	<b>170</b>

Source: Company reports, UBS estimates

*For more detail ETR, please see our other recent reports:*  
[2/22/2016: Industrial 'Evolution'](#)

[2/18/2016: Trimming Sales Expectations Again](#)

[11/3/2015: Two Things are Certain in Life: Retirement & Taxes](#)

[10/9/2015: Kickstarting the Exit Process](#)

## Valuation: Increasing PT to \$72, maintain Sell rating

We include our latest sum-of-the-parts valuation which reflects the improvement in the peer P/E multiple. While we note only ascribe a negative value of the merchant EWC business, we continue to apply a discounted multiple to the consolidated regulated entities. While we appreciate recent success in Arkansas on improving its regulatory construct, we perceive recent datapoints on reviewing corporate leverage and tax policies as illustrative of the higher risk jurisdictions and lower growth trajectories.

**Figure 135: Updated ETR Valuation: Still a Sell**

Entergy Corp. Sum-of-the-Parts Valuation								
	2018 EPS	P/E Multiple				Equity Value per Share		
		Low	Prem/Discount	Base	High	Low	Base	High
Regulated Utilities		2018 Peers	16.6x					
System Energy Resources, Inc. (SERI)	0.80	15.6x	0.0x	16.6x	17.6x	12.45	13.25	14.05
Entergy New Orleans	0.20	14.6x	-1.0x	15.6x	16.6x	2.95	3.16	3.36
Entergy Mississippi	0.88	14.6x	-1.0x	15.6x	16.6x	12.80	13.68	14.55
Entergy Louisiana	1.61	14.6x	-1.0x	15.6x	16.6x	23.54	25.15	26.76
Entergy Gulf States (Louisiana Only)	1.05	14.6x	-1.0x	15.6x	16.6x	15.38	16.44	17.49
Entergy Texas	0.61	14.1x	-1.5x	15.1x	16.1x	8.54	9.15	9.75
Entergy Arkansas	1.09	14.1x	-1.5x	15.1x	16.1x	15.32	16.40	17.49
Other	(0.14)	15.6x	0.0x	16.6x	17.6x	(2.13)	(2.27)	(2.40)
<b>Regulated Utility (Consolidated)</b>	<b>6.10</b>					<b>88.85</b>	<b>94.95</b>	<b>101.05</b>
Interest Expense	(0.38)	17.6x	0.0x	16.6x	15.6x	(6.65)	(6.27)	(5.89)
Parent Preferred Income	(0.71)	17.6x	0.0x	16.6x	15.6x	(12.47)	(11.77)	(11.06)
Other Parent Exp (non-Pfd)	(0.29)	17.6x	0.0x	16.6x	15.6x	(5.03)	(4.75)	(4.46)
<b>Total Utility Equity Value per Share</b>	<b>4.73</b>	<b>17.6x</b>	<b>15.1x</b>	<b>15.3x</b>	<b>18.1x</b>	<b>\$71.34</b>	<b>\$72.17</b>	<b>\$85.53</b>
Merchant Generation Equity Value/(Drag): NPV of FCF from 2016-2020						(1,736)	(527)	-
RISEC Sale Proceeds						540	540	540
Mn Shares Outstanding (2018E)						179	179	179
<b>Merchant Generation Equity Value per Share</b>						<b>(\$6.67)</b>	<b>\$0.07</b>	<b>\$3.01</b>
<b>Total Equity Value per Share</b>						<b>\$65.00</b>	<b>\$72.00</b>	<b>\$89.00</b>

Source: Company filings, FactSet, UBS estimates

# Eversource Energy

*A weak quarter, with mild weather only partially offset by decoupling. Also have several 1x positive regulatory items in 1Q15 that are absent this year.*

We forecast a wide miss on weather with \$0.75 in EPS for the quarter vs. consensus \$0.90. A very mild 1Q16 stands in stark contrast to last year's very cold 1Q15 (was +\$0.04 vs. normal), with an expected -\$0.10 year-over-year comp. We also see the absence of two one-time positive impacts from 1Q15: the +\$0.05 partial reversal of a bad debt writeoff at NSTAR Electric and the +\$0.04 partial reversal of over-reserved refunds for NSTAR Electric distribution capital recovery mechanisms. Offsetting these impacts is the absence of a -\$0.04 charge in 1Q15 for FERC transmission ROE, +\$0.05 of estimated increased revenues related to decoupling mechanisms at WMECO, CL&P, and NSTAR Gas, as well as \$0.02 of gas utility customer growth. We continue to expect a -2% improvement for overall O&M in 2016, although some (mostly deferred) storm expense was incurred in 1Q16, with an overall favorable comparison to 1Q15, when heavy snowfall tilted spending more in favor of O&M rather than capital investment.

Near-term success on Mass legislation thru June remains the principle potential driver of shares

We believe 1Q results could prove meaningfully weaker than Street

Figure 136: ES 1Q16E vs. 1Q15A Walk

1Q16 YoY EPS Waterfall	
<b>\$0.81</b>	<b>1Q15</b>
(0.10)	Very mild 1Q16 vs very cold 1Q15 (was +\$0.04 vs normal)
0.05	Yankee Gas, NSTAR Elec, and PSNH elec are not decoupled. WMECO and NSTAR Gas and CL&P are decoupled.
0.02	Gas sales growth 2%, or 10k-11k cust
(0.05)	1Q15 NSTAR Elec regulatory settlement - partial reversal of bad debt recovery writeoff due to favorable court decision
(0.04)	1Q15 NSTAR Elec regulatory settlement - partial reversal of over-reserved refunds to customers related to reliability and energy efficiency cost recovery mechanisms
0.04	Reversal (re-took the charge) of FERC Transmission ROE charge in 1Q15
0.01	O&M - Storm damage in 1Q16 (mostly deferred) from wind and snow in Feb. In 1Q15, some capital projects were put on hold for the snow, so had higher O&M expense in 1Q instead. Still expect -2% O&M for the year.
0.02	Transmission ratebase growth YoY ~\$450M (net of bonus depn) @ 11.0% ROE for new projects
(0.01)	Reduction for bonus depreciation, net of lower interest expense
0.01	NSTAR Gas rate increase \$15.8M Jan 1, 2016
0.00	Distribution growth at ES (0.0%-0.5%) - decoupling at CL&P and WMECO (about half the customers).
(0.02)	Expect 0.08-0.10 hit in FY2016 from Prop taxes, Depn, Storm Amort
0.01	ADIT earnings after CL&P decision (\$18M pretax; retroactive to Dec 1, 2014). Started booking in 2Q15.
-	Inc tax rates (37.5% in 1Q16 vs 37.5% in 1Q15)
<b>\$0.75</b>	<b>1Q16</b>
0.90	Street consensus EPS
2.90-3.05	2016 Guidance
\$2.99	UBSe 2016
\$3.00	Consensus 2016

Source: Company data, UBS estimates, company filings

## Estimates unchanged

The impact from bonus depreciation is estimated by management to be a \$300M reduction to cash taxes in 2016 and 2017 and a \$250M-\$300M retroactive refund for 2015. On the 4Q call, long-term EPS CAGR guidance was reduced 1% (a -\$0.10 impact by 2019) to a new range of 5%-7% off 2016 vs. the previous 6%-8%. The total effect of bonus depreciation is expected to be about -\$0.13 in 2019, with most of the impact felt in 2018 and 2019 (which we've already partially reflected in prior estimates). For 2015-2017, we expect bonus depreciation to only affect earnings for transmission investment since these projects are on formula rates. However, this negative impact is expected to be partially offset with the positive benefits of tax deferrals on distribution ratebase prior to ratecases in 2017

for 2018 rates. Beginning in 2018, we expect distribution ratebase to be reduced with new rates that year, although this effect is somewhat offset by the rating down of allowed bonus deductions in the latter part of the five-year extension. Our 2017-2019 estimates now reflect a 6.6% CAGR from 2016-2019.

The company's presentations from February 2016 and February 2015 (compared side by side in the table below) illustrate that most of the expected net reduction in ratebase growth due to bonus depreciation comes from distribution rather than transmission assets.

**Figure 137: Ratebase Growth & Capex Projections February 2016 Presentation vs. February 2015 Presentation (\$M)**

Ratebase Growth Projections Feb 2016 vs Feb 2015 (\$M)			
Transmission Ratebase	Feb 2016	Transmission Ratebase	Feb 2015
2014A	\$ 4,917	2013A	\$ 4,498
2015E	5,190	2014E	4,916
2016E	5,674	2015E	5,315
2017E	6,654	2016E	6,036
2018E	7,584	2017E	6,848
2019E	\$ 7,648	2018E	\$ 7,566
2015-2019 CAGR	10.2%	2014-2018 CAGR	11.4%
Total Ratebase Projection (\$B)		Total Ratebase Projection (\$B)	
2015E (yearend)	\$ 14.7	2013A (yearend)	\$ 13.6
Transmission	2.5	Transmission	2.7
Elec/Gas Dist & Gen	1.1	Elec/Gas Dist & Gen	2.4
2019E	\$ 18.3	2018E	\$ 18.6
Ratebase breakdown 2019E		Ratebase breakdown 2018E	
Elec Transmission	42%	Elec Transmission	41%
Elec Dist	48%	Elec Dist	46%
Gas Dist	10%	Gas Dist	10%
Elec Gen	0%	Elec Gen	3%
Capex 2016E-2019E		Capex 2015E-2018E	
Transmission	\$ 3,904	Transmission	\$ 3,875
Distribution/Gen	4,900	Distribution/Gen	4,186
Other (IT)	362	Other (IT)	359
Total	\$ 9,166	Total	\$ 8,420

Source: Company filings

As expected, 2016 EPS guidance was initiated on the 4Q call at \$2.90-\$3.05 vs. UBS estimate \$2.99 (**unchanged**) and consensus \$3.00. Major factors for 2016 include a +\$0.03 benefit from the NSTAR Gas ratecase and +\$0.03 at PSNH for the settlement that allows the utility to book a year of ratebase earnings on the Merrimack scrubber prior to a planned sale in early 2017. We also expect +\$0.07 (about 3%) lower O&M and +\$0.03 utility gas customer growth (2%). Transmission ratebase growth at 11.0% ROE for new projects helps +\$0.07, offset by higher depreciation and prop taxes -\$0.12. We expect modestly higher interest expense ~-\$0.01, although we see no significant refinancings in 2016E. With a 37%-38% tax rate expected for 2015 (a long-term high water mark), income tax expense should be lower in 2016E.

Figure 138: ES 2016E vs. 2015E Walk

2016E vs 2015E YoY EPS Waterfall	
<b>\$2.81 2015E UBSe (excludes \$0.05 integration costs)</b>	
-	Normalized weather - positive +\$0.06 impact through Sept 2015 but 4Q15 very mild.
(0.04)	net non-recurring regulatory items in 2015
0.04	Distribution growth at ES (0.0%-0.5%) - decoupling at CL&P and WMECO (about half the customers)
0.07	Transmission ratebase growth at 11.0% ROE for new projects
(0.01)	Reduction for bonus depreciation at Transmission, net of lower interest expense
0.03	Gas utility customer growth ~2%
0.03	NSTAR Gas rate increase
0.03	PSNH earnings on Merrimack scrubber
0.07	Reduced O&M about \$35M pretax
(0.12)	Higher depreciation and property taxes at ~\$0.03/quarter
(0.01)	Modestly higher interest expense
0.07	Lower tax rate, other items
<b>\$2.99 2016E UBSe</b>	
3.00	2016 Consensus
2.90-3.05	2016 guidance range

Source: Company data, UBS estimates, company filings

## Positive initial decision for New England transmission ROE, but there's a risk

On transmission ROEs, ES reinstated its reserve for lower FERC ROEs in 1Q15, with FERC leaning toward applying a transmission ROE cap for New England on a project-by-project basis rather than a whole-portfolio basis. This has the effect of reducing the ROEs to 11.74% for earlier projects in ES's portfolio that had been earning from 12.64%-13.10% (about half the Transmission ratebase – for example, NEEWS and Southwest CT lines built from 2005-2008). New projects earn an 11.0% ROE. As a result, the overall average ROE of the entire portfolio declined from ~12.5% to ~11.5% in 2015, with forward earnings impacted by -\$0.02 year over year on a quarterly basis throughout 2015.

On March 22<sup>nd</sup>, the Federal Energy Regulatory Commission (FERC) administrative law judge (ALJ) hearing the remaining two of three transmission ROE complaints in New England issued an Initial Decision (ID) with a potentially favorable impact on ES earnings for 2017 and beyond. As a reminder, the two remaining complaints for the 15-month periods 1/1/13-3/31/14 and 8/1/14-9/30/15 had been combined into a single proceeding with the pending final decision potentially establishing new precedent for ROE calculation methodology. However, the ID states that "anomalous capital market conditions" continued throughout the complaint periods, justifying continued use of the "upper midpoint" methodology within the peer proxy group "zone of reasonableness" to establish base ROE. The ID proposes a 9.59% base ROE with a cap of 10.42% for the 2<sup>nd</sup> complaint and a 10.90% base with 12.19% cap for the 3<sup>rd</sup> complaint. However, with the proxy group expected to exclude ITC from future calculations and bonus depreciation also suppressing growth, we expect lower ROE results in any future case. See our [3/23 note "Benefiting from Anomalous Conditions, for Now"](#) for more detail.

## Could see positive \$0.05 EPS impact in 2017+

If approved as a final decision (likely not until 1H17), the higher ROEs set for the 3<sup>rd</sup> complaint would apply prospectively from that point on (i.e., no impact on 2016), raising ES's current rates. As noted above, current rates are based on a 10.57% base with 11.74% ceiling set in the first complaint back in 2014 (effectively a weighted average of ~11.5% for ES's ratebase including the 50 bps RTO

With the proxy group expected to exclude ITC from future calculations and bonus depreciation also suppressing growth, we expect lower ROE results in any future case

For the 3<sup>rd</sup> complaint, the Initial Decision sets a 10.90% base with 12.19% cap, higher than current rates

incentive). Based on a 30-40 bps ROE improvement on ~\$5.2B of transmission ratebase at year-end 2015 with ~\$900M of growth through 2018 (~52% equity), this works out to an incremental~\$0.05 EPS by 2018E.

## Refund obligation likely to be immaterial

ES has reserved revenue overcollection to bring down earned ROEs to the 10.57%/11.74% level established in the 1st complaint. If the initial decision stands as the final order, ES is effectively under-reserved by ~100 bps for the 2<sup>nd</sup> complaint and over-reserved by about 30-40 bps for the 3<sup>rd</sup> complaint. While it is unclear at this time if ES is required to adjust reserves for the 1Q16 earnings report, the resulting 1x refund in a final order would be about \$25M-\$30M (about \$0.05/sh after tax).

## Partial credit for NPT and Access Northeast projects

We continue to include AFUDC during construction in 2019 for ES's 40% ownership of the Access Northeast project (at an 80% probability); although our comfort on Access Northeast continues to grow. We assign a 66% probability for NPT in our numbers as well. We do not include any credit for the recently proposed \$400M Clean Energy Connect transmission line.

**We do not include any credit for the recently proposed \$400M Clean Energy Connect transmission line**

**Figure 139: Estimated ES Uplift from Gas Pipe Investment (\$ Mn except EPS)**

Estimates ES Uplift from Gas Pipe Investment (\$M except EPS)	
\$M for Aggregate Project	3,000
ES Portion	1,200
Project Equity	50%
Targeted equity return (UBSe)	11.1%
Net Income Opportunity for ES Project Share	\$ 67
Shares O/S	318
EPS Opportunity	\$ 0.21
UBSe probability	80%
UBSe 2019 EPS	\$ 0.17

Source: Company filings, UBS estimates

While we see some risk for slippage on the Northern Pass, conversely, we see growing potential for Access Northeast. As such, these could help offset should one prove delayed relative to the low-probability on the other.

Figure 140: ES Estimates vs. Consensus, 2013A-2019E

Annual EPS	2013A	2014A	2015E	2016E	2017E	2018E	2019E
Transmission	\$0.59	\$0.64	\$0.76	\$0.70	\$0.74	\$0.77	\$0.80
Distribution, Generation	0.83	0.81	0.90	0.97	0.97	0.99	1.00
Yankee	0.13	0.15	0.14	0.15	0.17	0.17	0.17
Northern Pass @ 66% probability	0.00	0.01	0.01	0.02	0.09	0.13	0.17
Access Northeast @ 80% probability	0.00	0.00	0.00	0.02	0.05	0.12	0.17
NSTAR, Corp & Other	0.98	1.14	0.99	1.13	1.15	1.21	1.29
<b>UBSe</b>	<b>\$2.53</b>	<b>\$2.75</b>	<b>\$2.81</b>	<b>\$2.99</b>	<b>\$3.17</b>	<b>\$3.40</b>	<b>\$3.60</b>
CL&P Dist ROE	7.9%	8.6%	8.0%	9.3%	9.4%	9.3%	9.3%
PSNH Dist ROE	9.2%	9.3%	9.7%	9.7%	9.4%	9.4%	9.6%
Prior	\$2.53	\$2.75	\$2.81	\$2.99	\$3.17	\$3.40	\$3.60
<b>Consensus</b>			<b>\$2.81</b>	<b>\$3.00</b>	<b>\$3.18</b>	<b>\$3.39</b>	
<b>Guidance</b>				<b>\$2.90-\$3.05</b>			
5%-7% EPS growth from 2016 \$2.90-\$3.05 to 2019				UBSe 2016-19 CAGR		6.6%	
Annual EPS, by subsidiary	2013A	2014A	2015E	2016E	2017E	2018E	2019E
CL&P	\$ 0.88	\$ 0.91	\$ 1.04	\$ 1.05	\$ 1.08	\$ 1.10	\$ 1.13
PSNH	0.35	0.36	0.39	0.47	0.40	0.37	0.38
WMECO	0.19	0.18	0.23	0.24	0.26	0.28	0.29
Yankee	0.13	0.15	0.14	0.15	0.17	0.17	0.17
NSTAR Elec	0.85	0.95	0.93	0.95	0.95	0.98	0.99
NSTAR Gas	0.07	0.08	0.08	0.11	0.12	0.13	0.14
Corp & Other (includes NPT)	0.01	(0.00)	0.01	0.03	0.19	0.37	0.50
<b>Total</b>	<b>\$ 2.49</b>	<b>\$ 2.63</b>	<b>\$ 2.83</b>	<b>\$ 2.99</b>	<b>\$ 3.17</b>	<b>\$ 3.40</b>	<b>\$ 3.60</b>
<b>Consensus</b>			<b>\$ 2.81</b>	<b>\$ 3.00</b>	<b>\$ 3.18</b>	<b>\$ 3.39</b>	

Note: 2014 and 2013 represent GAAP.

Source: Company filings, UBS estimates, FactSet

## PT raised \$2 to \$61 for higher peer 2018E P/E multiple

Our SOTP valuation is based on a premium to the 2018E peer P/E and reflects our growing confidence on underlying major growth projects. We see ES as benefitting structurally from the among the best underlying infrastructure growth opportunities as the region attempts to execute on an ambitious slew of energy policy aspirations, largely relying on adjacent regions to provide the necessary energy supply 'diversity' given the rapidly dwindling diversity contributions from nuclear and coal.

The Northern Pass and Access Northeast projects are valued by discounting their earnings in 2019E to the valuation year and applying the average peer 2018E P/E (with a 1.5x premium for transmission and a 1.0x premium for gas transportation). We attribute ~\$4/sh to the Northern Pass project at a 66% probability and believe investors could more fully ascribe this in their valuations in 2016-2017 as key project hurdles are achieved. We give an 80% probability weighting to the proposed Access Northeast Pipeline partnership with Spectra and National Grid, worth ~\$5/sh in our valuation. We continue to apply the peer multiple to the regulated electric/gas businesses as well as 1x and 1.5x premiums to Yankee Gas and ES Transmission, respectively.

Figure 141: ES Sum-of-the-Parts Valuation on 2018E P/E

Sum of the Parts 2018E			Low Case		Base Case		High Case	
Business Segment	Metric	2018E	Multiple	Value	Multiple	Value	Multiple	Value
<b>Regulated Business</b>			<b>Peer Multiple</b>		<b>16.6x</b>		<b>Premium</b>	
NU Franchised Electric (CT, NH, MA)	P/E	\$0.99	15.6x	\$4,937	0.0x	16.6x	\$5,253	\$5,570
NU Transmission	P/E	\$0.77	16.1x	\$3,945	1.5x	18.1x	\$4,435	\$4,680
NU Yankee Gas	P/E	\$0.17	16.6x	\$904	1.0x	17.6x	\$958	\$1,013
NSTAR (MA)	P/E	\$1.27	16.1x	\$6,490	0.5x	17.1x	\$6,893	\$7,297
Northern Pass 2019 EPS, Discounted 1-Yr	P/E at 66% prob	\$0.16	17.1x	\$0	66%	18.1x	\$902	\$1,370
Access Northeast Pipeline 2019 EPS, Discounted 1-Yr	P/E at 80% prob	\$0.16	16.6x	\$439	80%	17.6x	\$878	\$1,102
<b>NU Equity Value</b>				\$16,715		\$19,320		\$21,031
Fully Diluted Outstanding Shares (2018E)				318		318		318
<b>NU Equity Value per Share</b>				<b>\$53.00</b>		<b>\$61.00</b>		<b>\$66.00</b>

Source: Company filings, UBS estimates, FactSet

*For more detail on ES and related transmission issues, please see our other recent reports:*

- [3/30/16 Dousing the New England Grid](#)
- [3/23/16 Benefiting from Anomalous Conditions, for Now](#)
- [2/5/16 Adding to New England Import Prospects](#)
- [1/15/16 How Green Can New England Get?](#)
- [12/31/15 Picking a Price for the New England Auction](#)
- [12/23/15 MISO Transmission Wins Round One](#)
- [12/14/15 Going Eye to Eye with the Public on NPT](#)
- [12/1/15 Reading the Tea Leaves in DC](#)
- [11/5/15 Enhancing the Grid](#)
- [8/18/15 Tunneling Through to an Approval](#)
- [8/3/15 Pipe & Wire Plans Moving Right Along](#)
- [7/22/15 A Thumbs Up for Northern Pass](#)

## The Massachusetts legislation – really about Hydro

Following the reintroduction of Senate Bill 1965, feedback from industry sources indicates a strong possibility for legislation in MA this Summer that will include upwards of ~18TWh (~2GW) of contracting under an expanded Clean Energy RFP seeking low carbon resources to meet the states' Global Warming Solutions Act targets, given the need to address solar caps in the state. This could include upwards of ~1GW dedicated to hydro resources under some scenarios, a key upside to ES' efforts to execute on transmission imports from Canada.

In our recent meeting with Avangrid (AGR), management framed the prospects for this legislation as really about hydro, more so than the ongoing RFP across the three-states, which would appear focused on more conventional resources. We believe this would explain ES' decision to pursue the New York export project into New England. AGR appears keen to compete with ES on the export avenue with its own Canadian interconnection itself. While a modest investment to interconnect its Northern Maine wind projects into Canada, this remains pending an RFP to do so from New England to pursue the project. Expect this to become a more fully defined procurement project in the coming months.

**Mass bill could open the door to formal contracting for long-distance transmission from Canada**

**Next question is if ES is the winner of any such procurement process?**

## Selections coming for the Three-State Clean Energy RFP

Proposals were submitted on January 28<sup>th</sup>, with selection of winning projects from 4/26 through 7/26. The RFP is a joint proposal from MA, CT, and RI for 5 TWhs of carbon-free renewables and hydroelectric energy, with winning contracts submitted for regulatory approvals, expected in 'Summer' (biasing towards September). ES is participating with both the Northern Pass and [Clean Energy Connect](#) projects. We see this as yet another positive catalyst.

## CT draft natural gas RFP proposes final contract approvals by Jan 2017; Access Northeast to participate

The Connecticut Department of Energy and Environmental Protection (DEEP) issued its long-awaited draft RFP for Natural Gas Capacity, Liquefied Natural Gas (LNG), and Natural Gas Storage Procurement, with public comments due by March 29<sup>th</sup> before a final version is issued on April 11<sup>th</sup>, with final project determinations from May-July. Although this process is being kicked off later than MA and RI RFPs (where Access Northeast has already been chosen), the regulatory approval process has just begun in those states and is expected to continue through 2H16. In contrast, contracts awarded in this CT RFP will face a shorter statutory 90-day approval process from regulators at the CT Public Utilities Regulatory Authority (PURA). Ultimately, ES expects to have approved contracts in place for MA, RI, and CT by year-end or shortly thereafter.

In NH, the PUC issued an order January 19, 2016 accepting the staff report and said it will conduct a two-part review process as EDCs submit natural gas capacity contracts. In Maine, the state already ran an RFP in 2014, but bidders updated proposals in Dec 2015 and a decision on recommended solutions is expected in late-Spring 2016. Vermont is not expected to participate. Separately, a FERC pre-filing was submitted on November 3, 2015 with the full filing expected in mid-2016. The goal remains to have major sections of the pipeline in service for the winter of 2018/19. The attached LNG facilities would be finished last.

**Figure 142: Proposed Schedule for CT Natural Gas Procurement RFP**

3/9/2016	Issue Draft RFP and Request for Written Comments
3/29/2016	Written Comments on Draft RFP Due
4/11/2016	Issue Final RFP
4/18/2016	Deadline for Submission of Written Questions on Final RFP
4/26/2016	Deadline for DEEP to Post Q&A on DEEP's Website
5/6/2016	Proposals Due
May-July 2016	Final Gas Projects Identified – DEEP Determination Issued
10/31/2016	EDCs Submit Contracts to PURA for Review and Approval
1/30/2017	PURA Decision (Issued 90 Days from EDC submission of Contracts to PURA)
TBD	Execute Final Contract(s)

Source: Connecticut Department of Energy and Environmental Protection (DEEP)

# Exelon Corp.

Following the MISO auction the pressure will be on Exelon to work with IL stakeholders to craft legislation that supports the economics of its nuclear plants. With the legislature seemingly stalled in 2016 without a budget deal given the stalemate between the state legislature and the Governor, we look towards 2017 for any resolution of the roadblock. The question remains whether the 'sacrifice' of Clinton will catalyze a wider effort to push forward on any deal to save the balance of the portfolio with a 'market-based' carbon scheme in the state. Investor expectations remain quite low for successful legislation. Aside from ExGen we look for an update on POM accretion, the regulated EPS CAGR, and how POM capex will be financed.

We expect Exelon to report 1Q16 adjusted EPS of **\$0.64** with the financing cost from the Pepco transaction the primary driver. At the core utilities BGE and PECO are expected to be relatively flat while ComEd should exhibit modest growth. Management forecasts ExGen declining for FY16 and we expect a slight decline YoY. More meaningfully we see risk to the FY17 & FY18 ExGen gross margin guidance, which we discuss later in the section. Pepco closed late in 3Q16 and we expect a slight contribution from the new utilities but the associated financing cost is still far greater.

**We expect 1Q16 to be towards the midpoint of guidance versus consensus expectations at the top-end (\$0.69)**

**Figure 143: EXC 1Q16E Earnings Walk**

EPS	Exelon Corp 1Q16 Earnings Walk
<b>\$0.71</b>	<b>1Q15A Adjusted EPS</b>
<b>0.00</b>	<b>Baltimore Gas and Electric (BGE)</b>
0.01	Margin: ~\$200Mn Rate Request [\$300Mn ratebase increase]
(0.01)	O&M, D&A, and Other: Cost Cuts offsetting inflation
<b>(0.01)</b>	<b>PECO Energy (PECO)</b>
0.01	Margin: Rate Increase (\$127Mn January 2016) [\$500Mn ratebase]
(0.02)	O&M, D&A, and Other: Cost Cuts offsetting inflation
<b>0.03</b>	<b>Commonwealth Edison (ComEd)</b>
0.04	Ratebase Growth: \$1.3Bn Increase Pre-Bonus Depreciation
0.00	30-year Treasury Trend: 50bp = \$0.02/sh FY
(0.02)	O&M, D&A, and Other: \$0.01 Bonus D&A drag
<b>(0.03)</b>	<b>Exelon Generation (ExGen)</b>
(0.04)	Gross Margins: Normalization of cost to serve and MtM
0.02	O&M: Lower Costs net of Inflation
0.04	O&M: Refueling/Unplanned Outages (-\$0.04 impact in 1Q15)
(0.02)	D&A and Other
0.00	Effective Tax Rate: Expected to be similar to 2015
(0.02)	Other: Interest, Decommissioning, etc.
<b>(0.06)</b>	<b>PEPCO Holdings (POM)</b>
0.01	Contribution from Pepco
(0.03)	Interest Expense: \$4.2Bn @ 3.8% on June 11, 2015
(0.04)	Dilution: 57.5Mn shares @ \$32.48 on July 14, 2015
<b>\$0.64</b>	<b>1Q16A Adjusted EPS</b>
<b>\$0.60-\$0.70</b>	<b>1Q16 Guidance</b>
<b>\$0.69</b>	<b>1Q16 Consensus</b>
<b>\$2.57</b>	<b>2016 UBSe EPS</b>
<b>\$2.53</b>	<b>2016 Consensus</b>
<b>\$2.40-\$2.70</b>	<b>2016 Guidance</b>

Source: Company filings, FactSet, UBS estimates

*For additional context, please refer links to relevant recent reports below:*

[3/23/16 Third Time is the Charm \[POM Decision\]](#)

[3/4/16 Illinois – Losing The Nuclear Advantage.](#)

[2/5/16 Capital Allocation In Transition](#)

[1/13/16 We Just Can't Get There](#)

[11/2/15 Taking a Bite Out of Pepco Accretion](#)

[10/20/15 Exploring EDF's Nuclear Put on Exelon](#)

[9/28/15 A Concentrated Nuclear Play](#)

[9/10/15 Keeping the Nuclear Option Alive](#)

[8/31/15 Can Exelon Turn The Tide in DC?](#)

[8/26/15 Washington DC Puts Up a Stop Sign](#)

[7/31/15 Catalysts Galore](#)

## **What are the pivotal questions for EXC?**

### **What is the outlook for Pepco?**

- **Update on ratecase timing, ROE expectations, and ultimately EPS accretion will be the primary topic:** Exelon has previously guided to a -\$0.05 drag in 2016, which improves to +\$0.20 accretion by 2020 seemingly based on an 8% earned ROE. The current 2016 guidance is premised on POM not closing and management unwinding the financing cost of the transaction which management estimated at -\$0.07; therefore, given that POM closed about one month later than we do not expect a revision to FY16 guidance due to POM. For the future years we look for details to see if Exelon reaffirms the guidance or if POM's financial position has improved/deteriorated since the November update. Management has avoided providing updates on ratecase strategy thus far but on average Pepco historically filed ratecases every ~22 months across the jurisdictions with an average of eight months per case.
- **Bonus depreciation expected to have a relatively small impact on accretion:** Utilizing Pepco's last presentation, which is admittedly dated May 2014, there is ~\$1.1Bn of annual capex forecasted for 2015-2018 we estimate a \$5-\$10Mn impact from bonus depreciation (~\$0.01/sh) depending on the assumed ROE (8-10%). For context, the capex plan is modestly larger than PECO (\$675Mn) or BGE (\$800Mn) respective average annual plans. This could become a larger issue if Exelon looks to materially increase spending after the transaction.
- **Atlantic City Electric seeks rate increase, the first ratecase since August 2014:** Prior to closing the transaction Pepco Holdings subsidiary Atlantic City Electric (ACE) requested a \$78.9Mn rate increase premised on a 10.6% ROE. The company stated their present rates are "unjust and unreasonable" which cannot provide sufficient income to cover the costs associated with increased investment in their ratebase. Management cited the \$715.9 million deployment since 2011 on capital distribution system projects and the expected investments over the next several years as a basis for the rate increase.

ACE also proposed storm hardening/grid resiliency initiative (PowerAhead), which includes energy efficiency programs and increased distributed generation. **ACE plans to spend \$176 million** under this program and hopes to recover these costs through a rider proposed in their filing.

Following the approval of the POM transaction in late March investors are focused on how POM will impact the regulated EPS CAGR and whether there is upside/downside to the previous accretion disclosures for the deal

On average through 2015, the ROE authorized for electric utilities hovered around 9.6% while the approved return thus far in 2016 is approximately 9.7% nationwide. POM is requesting a 10.6% ROE

PEG's recent riders have had a 9.75% ROE

## How will the capital allocation plan evolve after closing POM?

- **What to do with the ExGen FCF?** Reinvest in the utility. We believe the story could yet continue to evolve to resemble PSEG as Exelon continues to emphasize regulated growth. With ~\$2.4Bn of contemplated long-term debt paydown in the period (aside from commercial paper), we see roughly ~\$1 Bn of truly available FCF to push back to the parent. We would not be surprised to see EXC reduce its ExGen debt reduction plan with POM opening up seemingly more value-enhancing spending opportunities.
- **What leverage is currently being targeted?:** Assuming no change in the plan, management stated that it is targeting \$3.6Bn of debt reduction including ~\$1.2Bn of low cost commercial paper. This implies \$2.4Bn of long-term debt reduction over the five-year period. We highlight the near-term maturities below, which also sum to the same \$2.4Bn.

Figure 144: ExGen Long-Term Debt Obligations

Exelon Generation (ExGen) Long-Term Debt Company		Funding Type	Issue Date	Intrest Rate	Maturity (\$Mn)	Maturity Date
<b>Debt as of 12/31/2014</b>						
(A)	Exelon Corporation	CEG Senior Notes	6/13/2003	4.55%	550	6/15/2015
	Exelon Generation Company, LLC	2007 Senior Unsecured Notes	9/28/2007	6.20%	700	10/1/2017
	Exelon Generation Company, LLC	2009 Senior Unsecured Notes	9/23/2009	5.20%	600	10/1/2019
	Exelon Generation Company, LLC	2010 Senior Unsecured Notes	9/30/2010	4.00%	550	10/1/2020
	Exelon Corporation	CEG Senior Notes	12/14/2010	5.15%	550	12/1/2020
	Exelon Generation Company, LLC	2012 Senior Unsecured Notes	6/18/2012	4.25%	523	6/15/2022
	Exelon Corporation	CEG Senior Notes	3/26/2002	7.60%	258	4/1/2032
	Exelon Generation Company, LLC	2009 Senior Unsecured Notes	9/23/2009	6.25%	900	10/1/2039
	Exelon Generation Company, LLC	2010 Senior Unsecured Notes	9/30/2010	5.75%	350	10/1/2041
	Exelon Generation Company, LLC	2012 Senior Unsecured Notes	6/18/2012	5.60%	788	6/15/2042
<b>New Issuances 1Q15-3Q15</b>						
	Exelon Generation Company, LLC	2015 Senior Unsecured Notes	1/15/2015	2.95%	750	1/15/2020
	Exelon Generation Company, LLC	Tax Exempt Pollution Control Revenue Bonds	6/1/2015	2.5%-2.7%	435	2019/2020
<b>New Retirement/Redemptions 1Q15-3Q15</b>						
(A)	Exelon Corporation	CEG Senior Notes	6/13/2003	4.55%	(550)	6/15/2015
<b>Total</b>				<b>5.01%</b>	<b>6,404</b>	

Source: Company filings, SNL Energy, UBS estimates

## What is the latest outlook for the merchant power subsidiary?

- **Will New York and Illinois reform the market to support nuclear?** In a recent interview Exelon management discussed its Nine Mile Point nuclear plant in upstate New York describing the asset as “losing a lot of money”. Although Entergy has already announced plans to close its single-unit Fitzpatrick nuclear plant on an adjacent site, we have been operating under the assumption that the cost profile of Nine Mile was notably better as it is a dual-unit site. Below we show our estimate of the economics below where we see modest negative FCF in 2016 with more a break-even forecast for 2018.

Management continues to advocate for Zero Emission Credits (ZEC) in New York [[details here](#)] to support the economics of its challenged merchant assets (Nine Mile and Ginna, the latter of which is currently operating under a reliability support agreement with the state). There appears to be political support for intervention to keep the nuclear plants open as evidenced by the NY Senate proposing \$100Mn of funds towards upstate nuclear assets; however, nothing has been finalized.

**“Nine Mile gets a little bit of a benefit because it is a dual-unit (plant), but it is losing money. And it’s losing a lot of money.” – EXC management**

**Exelon owns ~47% of the capacity via its Constellation joint venture (Long Island Power Authority [LIPA] owns 18% of Unit 2)**

Ultimately, with Ginna likely losing \$50+Mn/yr without any subsidy (it benefits from an RSSA arrangement today through March 2017) and Nine Mile (no RSSA) also likely FCF negative, we see accretive benefits to the company from any reforms that can remedy the cash drag. Bottom line, adding ZEC value to Nine Mile would be a further positive, with timeline pointing to this summer for resolution.

**We expect management to continue emphasizing the magnitude of nuclear FCF losses publicly as it advocates for legislative/regulatory reform in both New York and Illinois**

**The Last Mile for the Nine Mile Nuke?**

**Figure 145: Nine Mile Point Mini Model**

<b>Nine Mile Point</b>	<b>2015</b>	<b>2016</b>	<b>2017</b>	<b>2018</b>
Capacity (MW)	1,564	1,564	1,564	1,564
Capacity Price (\$/kW-yr)	37	44	69	57
EFOR	5%	5%	5%	5%
Capacity Payments	55	65	103	85
Market Power Prices (\$/MWh)	38	32	33	32
Generation (TWh)	14	13	13	13
Energy Revenue (\$ Mn)	518	424	442	435
<b>Total Revenues</b>	<b>574</b>	<b>489</b>	<b>544</b>	<b>520</b>
Nuclear Fuel Capex (\$/MWh)	6.00	6.30	6.62	6.95
Nuclear Fuel (\$ Mn)	(82)	(84)	(89)	(93)
<b>Gross Margin</b>	<b>492</b>	<b>405</b>	<b>455</b>	<b>427</b>
Direct O&M	(291)	(291)	(291)	(291)
Other O&M	(56)	(56)	(56)	(56)
Total Costs	(347)	(347)	(347)	(347)
Implied \$/kW-yr	222	222	222	222
<b>EBITDA</b>	<b>145</b>	<b>58</b>	<b>108</b>	<b>80</b>
Maintenance Capex	(81)	(81)	(81)	(81)
<b>FCF</b>	<b>63</b>	<b>(24)</b>	<b>27</b>	<b>(2)</b>

Source: Company filings, SNL Energy, Platts, UBS estimates

- **MISO capacity auction clears down ~50% YoY:** In the MISO 2016/2017 auction the key zones 2-7 (Illinois and Michigan are the primary investor focus) cleared at \$72/MW-day, down from \$150/MW-day in the prior year's auction but the result was modestly ahead of UBS estimates (\$50/MW-day) and meaningfully ahead of even lower Street expectations. The auction cleared in a highly-sensitive portion of the demand curve and a +/- ~185MW change in capacity was the difference between ~\$25/MW-day and \$110/MW-day.

Exelon continued its trend of bidding its 1,069MW Clinton nuclear plant as a price taker and cleared that 2016/2017 auction but stated that it would "prepare for a potential early retirement." Management reconfirmed that Clinton is free cash flow negative, consistent with our models, and we continue to expect a formal retirement announcement in September to take effect in Spring 2017.

**Will potentially retiring Clinton early be a catalyst for legislative action in Illinois to support the economics of Exelon's nuclear plants?**

▪ **Prior to the MISO auction Crane warned of a Clinton retirement:**

According to media reports (Crane's Chicago), Exelon's CEO Chris Crane was meeting with key Illinois politicians (House/Senate/Governor) in March indicating that it will close its 1.1GW Clinton Power Station nuclear plant if legislation is not passed that helps supplement its operations. Last year Exelon supported proposed legislation which would have introduced a Low Carbon Portfolio Standard (LCPS) but Illinois has seen little progress given the continuing debate over the State's budget. We expect Exelon to support a new version of the proposed legislation this year which has a lower level of compensation for its nuclear plants and has more concessions to other energy stakeholders (coal and renewables). After a failed effort in 2015 there could be an uphill battle in 2016 as stakeholders have reported that parties are not close to a deal; however, this is still the early days of the current year's legislative process.

Reforms in MISO and Illinois would serve to improve the outlook for Exelon's merchant fleet but the extension of the wind Production Tax Credit (PTC) should continue to pressure unregulated generators. Bottom line, with wind at \$20-\$35/MWh, the prospects for conventional generation in the Midwest are dim. Coal and nuclear retirements should improve pricing, but we question whether it will be enough to counter the continued growth of renewables.

- **Industry aims to reduce costs back to 2002 levels by end of decade:** We hosted our latest conference call with the Nuclear Energy Institute NEI to discuss the latest industry-wide plan to bring down costs back to the 2002 level of \$28/MWh by 2020, leveraging reductions on capex, O&M, and nuclear fuel. Aggressive goals, which many investors view with justifiable scepticism, appear more plausible in a scenario where both capex and fuel costs continue to undergo a structural shift over the next few years. Capex peak of almost ~\$11B in 2012 could be a cycle high for the medium term as many plants were transitioning from 40- to 60-year operating timeframes and upgrading expensive components like steam generators and reactor vessel heads. Further, Uranium price declines may still have a significant role to play in cost deflation as five-year hedges roll off in a depressed commodity environment. On the other hand, O&M remains an area for significant improvement and relatively flat O&M costs aren't helping the cost story when ~58% of total costs were operating-related last year.

[For further details please refer to our recent note and transcript on the topic based on our conversation with NEI.](#)

Even before the sharp decline in the MISO auction, EXC was reengaging with politicians but per media reports the multiple stakeholders were not close to a deal

A weak merchant energy price environment in ComEd plus a potential drop in MISO Zone 4 capacity prices could seal the fate of Clinton, in our view

Reducing nuclear costs should help to improve the viability of Exelon's fleet. Exelon's cost-cutting initiative disclosed in November 2015 was heavily focused on reducing merchant expenses

## Reducing EPS estimates at the GenCo as power falls

We see risk to ExGen's gross margin guidance which was based on the 12/31/15 \$29/MWh reference price for NiHub ATC but is now trading below \$27/MWh (~\$26.75/MWh as of 3/31, the expected new reference date). In the Midwest alone based on Exelon's sensitivities we see the potential for a ~\$100Mn (~57% hedged) reduction in 2017 and ~\$150Mn (~23% hedged) in 2018. While Exelon has not disclosed 2019 gross margin expectations we assume the company is minimally hedged for the year as management continues to be bullish on the long-term prospects for NI-Hub based on multiple meetings with management. The wildcard is whether/how much additional retail margin has been secured to offset weaker power prices.

Given the sharp compression in EV/EBITDA values for IPPs, we continue to see relative P/E multiples as less informative for EXC. While admittedly it appears quite cheap vs. peers on historic P/E metrics, most investors continue to frame the story in the context of a total SOP value.

**Figure 146: Updated Exelon EPS Estimates; does not include POM**

<b>Exelon Consolidated EPS</b>	<b>2015</b>	<b>2016</b>	<b>2017</b>	<b>2018</b>	<b>2019</b>
PECO	0.43	0.45	0.47	0.51	0.55
ComEd	0.48	0.55	0.57	0.63	0.70
BGE	0.31	0.31	0.34	0.37	0.39
Exelon Generation	1.40	1.31	1.27	1.32	1.15
Other	(0.13)	(0.06)	(0.06)	(0.05)	(0.05)
<b>Total EPS</b>	<b>2.49</b>	<b>2.57</b>	<b>2.59</b>	<b>2.77</b>	<b>2.74</b>
<b>Guidance</b>	<b>\$2.60</b>	<b>\$2.70</b>			
<b>Consensus</b>	<b>2.52</b>	<b>2.53</b>	<b>2.66</b>	<b>2.77</b>	<b>2.94</b>
<i>Prior UBS estimates</i>	2.49	2.56	2.61	2.84	2.98
<i>Accretion from POM Deal</i>	(0.13)	(0.05)	-	0.07-0.12	0.18
<i>Regulated EPS (UBSe)</i>	\$1.22	\$1.32	\$1.38	\$1.51	\$1.64
<i>Regulated Guidance Midpoint</i>	\$1.24	\$1.34	\$1.42	\$1.50	N/A
<i>Dividend Per Share</i>	\$1.24	\$1.26	\$1.29	\$1.32	\$1.35
<i>Utility Payout Ratio (Ex-POM)</i>	102%	95%	93%	88%	82%
<i>Utility Payout Ratio (W./-POM)</i>	114%	99%	93%	82%	74%

Source: Company filings, FactSet, UBS estimates

# FirstEnergy Corp.

FE is largely flat following the PUCO approval of the PPAs as investors increasingly see a possibility that the FERC issues an adverse order. No material updates are expected on the 1Q call. Management does not intend to provide '16 guidance despite the approval of the PPA – we view this as a cautious datapoint. We include the full value of the PPA in our price target which appears consistent with how investors are valuing the company (~\$3/sh premium over an in-line P/E multiple).

We forecast FE reporting adjusted 1Q16 EPS of **\$0.75** at the low-end of the guidance range (\$0.75-\$0.85) and below consensus (\$0.76). The new rates in Pennsylvania should offset the headwinds from weather and leave the regulated utility largely flat YoY. Management has not provided guidance for 2016 so we look for updates on datapoints for how sales have trended. FE has stated they expect ~flat sales with positive shale activity (although a significantly slower growth rate) offsetting reduced residential activity. While most commodity sensitive businesses across the group are expected to decline versus 2015, FES posted a particularly weak quarter in 1Q15 (+\$0.05 ongoing EPS; -\$0.02 GAAP EPS) and benefits in 1Q16 from the significantly higher ATSI capacity prices for the period (\$357/MW-day compared with \$126/MW-day).

The step-up from ATSI capacity pricing is the most significant factor which more than compensates for ~flat utility performance given the negative weather

Figure 147: FE 4Q15 Earnings Walk

FirstEnergy 1Q16 Earnings Walk	EPS
<b>1Q15A Adjusted EPS</b>	<b>\$0.62</b>
<b>Regulated Distribution:</b>	
Weather vs Normal in 1Q15 Degree Days +20%	(0.04)
Weather vs Normal in 1Q16 Degree Days -25%	(0.05)
Distribution Sales Growth: Slightly Negative	(0.01)
WV: \$13Mn Pre-Tax Earnings Impact; Effective ~Mar. 2015	0.00
PA: \$205Mn Pre-Tax Earnings Impact; Effective May 2015	0.08
PA: LTIP Investment: \$56Mn expected to be deployed in '16	0.00
JCP&L: +~\$20Mn Net Rev Increase; Effective April 2015	0.01
O&M: Approximately flat due to CF plan and NJ reversal	0.01
Pension & OPEB (MtM excluded from ongoing)	(0.02)
Depreciation & Amortization and Property Taxes	(0.01)
Investment Income and Financing Costs	-
<b>Regulated Transmission:</b>	
Revenues net of D&A and taxes: Higher ratebase	0.01
Financing, Taxes, and Other	-
<b>First Energy Solutions (FES):</b>	
Commodity Margin: Higher capacity and lower cost to serve	0.20
Depreciation, O&M, Pension, and Other	(0.03)
Reduced Investment Income	(0.01)
<b>Parent &amp; Other:</b>	
Parent Drag: 36.0% in 2015 vs ~37.5% Normal Tax Rate	(0.01)
Dilution	(0.00)
<b>1Q16E Adjusted EPS</b>	<b>\$0.75</b>
<b>1Q16 Consensus</b>	<b>0.72</b>
<b>1Q16 Guidance</b>	<b>\$0.75-\$0.85</b>
<b>2016 UBSe EPS</b>	<b>\$2.85</b>
<b>2016 Consensus</b>	<b>\$2.84</b>
<b>2016 Expected Guidance Range (\$2.85 Midpoint)</b>	<b>\$2.70-\$3.00</b>

Source: Company filings, FactSet, UBS estimates

Once again management does **not** intend to provide 2016 guidance despite the PUCO approval, opting to wait for resolution from FERC. We view this caution as a negative datapoint. Below we present our latest YoY earnings walk attempt to forecast expectations for 2016 with the biggest assumption relating to whether or not FE earns on its PPA in Ohio. Our estimate is ~\$0.05/sh low based primarily on the challenging weather.

Only with the contribution from the Ohio PPA do we forecast growth in 2016

Additional details on the segment drivers are available in our 3Q15 FE note, [In a Holding Pattern Above Columbus](#).

**Figure 148: FE 2016E Earnings Walk**

<b>FirstEnergy Corp. Earnings Walk</b>	<b>EPS</b>
<b>2015E EPS</b>	<b>\$2.71</b>
<b>Regulated Distribution:</b>	
Reversal of Estimated Weather in 2015	(0.04)
Impact of Weather in 2016	(0.05)
Distribution Sales Growth: Slightly negative	(0.02)
JCP&L: -\$34.4Mn Rev Decrease; Effective April 2015	0.01
PA: \$205Mn Pre-Tax Earnings Impact; Effective May 2015	0.10
PA: DSIC Investment: \$56Mn expected to be deployed in '16	0.01
WV: \$13Mn Pre-Tax Earnings Impact; Effective ~Mar. 2015	0.00
O&M: Approximately flat due to CF plan and NJ reversal	0.03
Pension & OPEB (MtM excluded from ongoing)	(0.06)
Depreciation & Amortization and Property Taxes	(0.04)
Investment Income and Financing Costs	-
<b>Regulated Transmission:</b>	
Revenues net of D&A and taxes: Higher ratebase	0.03
Financing, Taxes, and Other	-
<b>First Energy Solutions (FES):</b>	
'15: ~\$250Mn NI UBSe     '16: Guidance Midpoint \$250Mn	-
Estimated MtM Decline in Open EBITDA	(0.05)
Potential PPA Uplift (Half-Year)	0.23
<b>Parent &amp; Other:</b>	
Parent Drag: 36.7% in 2015 vs ~37.5% Normal Tax Rate	(0.03)
Dilution	0.00
<b>2016E EPS</b>	<b>\$2.85</b>
<b>2016E Consensus</b>	<b>\$2.84</b>
<b>2016 Expected Guidance Range (\$2.85 Midpoint)</b>	<b>\$2.70-\$3.00</b>

Source: Company filings, FactSet, UBS estimates

*For additional context, please refer links to relevant recent reports below:*

[2/17/16 Pension Woes](#)

[12/2/15 At the Goalline in Columbus](#)

[11/2/15 In a Holding Pattern Above Columbus](#)

[10/13/15 Will Ohio Come Through?](#)

[8/3/15 Keeping Up With The Jones](#)

[5/4/15 Carving Out Another Chunk of Change](#)

[3/19/15 More March Madness in Columbus](#)

[2/20/15 Hitting The Reset Button Again](#)

## What are the pivotal questions for FE?

### What is the latest outlook for the Ohio ESP?

- **PUCO approves both AEP and FE contracts with minimal changes:** On March 31, the Public Utilities Commission of Ohio (PUCO) approved the power purchase agreement (PPA) and retail rate stability (RRS) rider components of AEP and FE's pending Electric Security Plans (ESP) with modifications. For FE, the PUCO mandates no total bill increase for the first two years but while AEP's rider mechanism cannot cause more than 5% inflation with any 'capped' compensation subject to deferral beyond the period (i.e., no compensation is permanently forgone by the companies). We detail what we see as the primary Commission modifications later in the section but we do not believe any of the alternations are significant enough to have a material negative impact on the economics for FE.

[Ohio Docket 14-1297-EL-SSO: FirstEnergy](#)

- **Muted response for shares following approval highlights investor concern:** The vast majority of investors we have spoken with expected the PUCO to approve the PPA/RRS riders so we were not surprised by the lack of response in shares in days following the deal. The real question will be whether the riders can withstand FERC/judicial scrutiny with merchant generations already having pledged to challenge the contracts. The FERC does not have a mandatory timeframe to respond to the latest 206 complaint filed in early February. We continue to see challenges around the 'Affiliate Rules' (Edgar/Allegheny standards) as a key risk that could restrain the performance of FE. Ultimately if the FERC rejects the agreements on the basis that contracts were not executed in a sufficiently independent manner between affiliates, the parties including FE and AEP could push the subject in other ways, seeking other structures with settling parties if not legislation outright to allow for re-regulation in the state.
- **Legislative angle becomes more viable? RPS Freeze is good indicator on PPA legislative deal viability:** On April 13<sup>th</sup> state Senators in Ohio were circulating a draft bill which would extend the renewable mandate freeze in the state, despite the notable public opposition of Governor Kasich. Potential success of this legislation could bode well for any future efforts to put forth legislation (already contemplated by FE) should the companies (AEP & FE) lose at their efforts to win support of their PPAs at the FERC. Timing on a FERC decision would seemingly push any potential PPA-related legislative effort into 2017 in contrast to the renewables bill being discussed today. Recall that the Governor's recently appointed the Chair of the PUCO voted in favor of the PPA, indicating support for the potential customer benefits. That said, higher bills would likely face pushback from consumers as it has already – making it a sticking issue. In contrast, freezing the renewables may appear to be palatable given the eventual implementation of the Clean Power Plan (CPP) regardless.
- **What is the timeline? There are two paths of scrutiny:** The most immediate venue to track is at the FERC with petitions against both FE (Docket EL16-34) and AEP (Docket EL16-33). The next FERC meeting is April 21<sup>st</sup> although a decision could come at any time – for example FERC could simply opt to not take up the petition. The PUCO has filed comments in the FERC dockets citing retail access to competitive supply (52% comm/industrial and 32% resi are shopping) as justification for the contracts. Furthermore, noting that regulated plants widely participate in PJM capacity markets, they argue against a proposed Minimum Offer Price Rule (MOPR) application in Ohio as

FE reached a settlement in December with minimal degradation from its original ask – this was substantially approved by the PUCO with few modifications

Will there be resolution on the PPAs before the PJM capacity auction in May?

PUCO pushes back at FERC to keep PPA structures intact

unjustly discriminatory. No comment was made on the affiliate waiver, which could be vulnerable in our view based on precedent cases.

On the judicial front the parties have 30-days to request rehearing of the PUCO Order which would seemingly push any potential appeal to the state Supreme Court back to May/June.

### What was modified in the PUCO order?

- **Keeping bill at least flat for two years:** The PUCO modified the order to request that average customer bills do not increase for the first two years (June 1, 2016 - May 31, 2018) of the ESP. As this comment relates to the total bill, we would expect reductions in generation cost of service rider to create headroom in the customer bill such that this stipulation does not materially impact the economics of the RRS. Furthermore the PUCO allows FE to defer expenses and permit recovery beginning in June 2018.
- **C&I mitigation mechanism:** FE must collaborate with the PUCO Staff to establish a phase-in plan for C&I customers with above-average rate impacts from the PPA.
- **Reducing customer risk of CP and outages:** The costs of capacity performance (CP) penalties will be borne by shareholders rather than Ohio customers; however, shareholders would have a claim on any bonus payments rather than customers. Similarly the rider cannot charge customers for a forced outage lasting more than ninety days.
- **Retirement costs:** Customers will not pay for plant retirement costs.
- **Additional oversight:** Requirement that file compliance reports at least annually detailing the funding for low- and moderate-income customer assistance programs. If the Commission wishes it can request an independent audit of the compliance reports at the expense of shareholders.
- **Renewables:** The requirement that FE procure 100MW was strengthened by removing the linkage to environmental laws or regulations. Additionally FE must pursue solar as part of the 100MW renewables commitment and document its efforts; however, does not ultimately have to sign-up any solar contracts as part of the renewables commitment. Management must submit a fuel diversity report every four years rather than five years as previously contemplated.
- **Alternative Energy Resource Rider:** Refund decisions will be decided on case-by-case basis rather than being limited in all cases.
- **PJM reopener:** The PUCO added a provision such that it can modify the terms of the ESP if PJM alters its rules/tariffs in the future.

**"The Commission does not believe that the evidence supports OCC and NOPEC's prediction that we have entered a period of energy price Utopia where the price of natural gas, electricity and oil remains flat for a period of 15 years." - PUCO**

*For further details on the Ohio proceedings, please refer to reports below:*

[Ohio: Scoring a Contract](#)

[Ohio: Is Re-Regulation on the Table?](#)

[PJM's Ohio Conundrum](#)

[FE: At the Goal Line in Columbus](#)

[AEP: Buying into Ohio](#)

- **Analyst Day timing is now contingent on clarity from the FERC rather than just PUCO approval:** Previously management had pointed to a potential Analyst Day in March-April following the PUCO approval of the ESP. The Analyst Day is critical as this is where we expect an update on equity needs and at least preliminary details on regulated spending (TransCos, PA, NJ, and Ohio) underpinning the regulated plus parent EPS CAGR. The West Virginia IRP filing could also offer clues for that jurisdiction.

Next we look to see how the PPA revenues will help to offset any potential equity needs given the desire to improve the credit metrics

In the absence of the PPA we think FE could potentially look to issue up to ~\$1Bn of equity to improve its credit metrics

#### What is the outlook for growth at the regulated utilities?

- **Ohio ESP has favorable elements for the Ohio distribution utility as well:** Although the proposed settlement suggests a freeze on distribution base rates during the PPA duration the utilities would grow via the DCR rider at a minimum enabling \$30 Mn in per-annum growth in net income (~\$0.04/yr). The more material growth relates to smart grid with a 10.88% ROE (10.38% base plus a 50% incentive mechanism) and would allow for full de-coupling as well.
- **Looking beyond Ohio, focus returns squarely to regulated growth profile:** If the Ohio PPAs up-stand scrutiny we would expect a similar request eventually for its 1.3GW Pleasants plant in West Virginia which FE has spent ~\$650Mn on environmental capex. In Oct 2013 Mon Power transferred 8% of Pleasants to Allegheny Energy Supply at \$73Mn, implying ~\$910Mn of value.
- **NJ also ripe for reinvestment:** Turning to the other regulated opportunities FE has been having conversations with the NJ Board of Public Utilities (BPU) when permissible and has communicated its desire to increase spending in the territory but must weigh the opportunities against deployment opportunities in other jurisdictions. In 3Q15 FE disclosed plans to invest \$25Mn of O&M in 4Q15 which is designed to show management's commitment to improving operations in New Jersey. Earnings declined sharply in JCP&L in 2015 as a result of the higher spending and although FE has not indicated when it plans to file, we expect an update in the near term.

Pursuing a Wider Regulated Strategy: *More to Come?*

## Updated Earnings Estimates

We include our latest projections which reflect the latest mark-to-market for the FirstEnergy Solutions subsidiary and minor adjustments to the regulated utilities based on each subsidiary's annual filings. The regulated EPS trajectory remains the key focus of many investors which we include in the Figure below but we emphasize that we have not yet reflected any additional dilution.

**Figure 149: Updated FE EPS Projections**

UBS Adjusted EPS Estimates	2013A	2014A	2015E	2016E	2017E	2018E
Energy Delivery	2.05	1.92	1.82	1.87	2.01	2.17
FirstEnergy Solutions	0.73	0.22	0.62	0.74	0.36	0.31
Transmission (ATSI, Trail, and OpCo's)	0.51	0.53	0.71	0.73	0.82	0.85
Parent & Other	(0.25)	(0.13)	(0.44)	(0.50)	(0.51)	(0.54)
<b>Total UBS EPS</b>	<b>3.04</b>	<b>2.53</b>	<b>2.71</b>	<b>2.85</b>	<b>2.68</b>	<b>2.79</b>
Previous UBS (except Guidance)			2.71	2.87	2.83	2.87
Guidance		\$2.67-\$2.75				
Consensus (4/15/16)		2.50	2.69	2.84	2.71	2.70
Regulated & Parent EPS-Only			2.09	2.10	2.32	2.48
Regulated (T&D)	2.56	2.45	2.53	2.60	2.83	3.03

Source: Company filings, FactSet, UBS estimates

## Valuation: Increase price target to \$35

We are rolling our valuation forward to 2018E where we continue to use a sum-of-the-parts methodology with P/E multiples for the regulated utilities and non-interest parent drag. With the major ratecases completed in NJ, PA, and WV we previously have reduced the distribution P/E discount to 0.5x from 1.0x previously but maintain the discount given the lack of load growth projected (~flat expectations for 2016). We continue to net out the parent debt given the magnitude, utilization of revolver which understates interest expense, and overall risk profile for the generation (assuming FES is non-recourse). The PPA continues to represent ~\$3/sh in our valuation.

The majority of the increase in our price target is driven by the increase in the peer multiples for the regulated group

Figure 150: FE Sum-of-the-Parts Valuation

Regulated Utilities	2018 Net Income	P/E Multiple				Equity Value			
		Low	Peers	Premium/ Discount	Base	High	Low	Base	High
<u>Core Utilities</u>									
Energy Delivery (FE and AYE Utilities)	921	14.5x	16.0x	-0.5x	15.5x	16.5x	\$13,355	\$14,276	\$15,197
Add'l Utility Capex NI @ \$ 1Bn Spend	50					16.5x			\$825
Transmission (ATSI, TRAIL)	362	16.0x	16.0x	1.0x	17.0x	18.0x	\$5,794	\$6,156	\$6,519
<i>Total EPS</i>	<i>3.03</i>								
<u>Parent Costs</u>									
Net HoldCo/Parent Expenses (SG&A, etc)	(230)	15.0x	16.0x	0.0x	16.0x	17.0x	(\$3,444)	(\$3,673)	(\$3,903)
Add Back: Parent Interest Expense	128	15.0x	16.0x	0.0x	16.0x	17.0x	\$1,927	\$2,055	\$2,184
<i>Net Parent EPS (SG&amp;A ex-Interest)</i>	<i>(0.24)</i>								
Total / Implied Utilities	1,232	14.3x			15.3x	16.9x	\$17,632	\$18,814	\$20,821
<i>Total Regulated EPS</i>	<i>2.91</i>								
Number of Shares Outstanding - 2018 (Mn)							424	424	433
Regulated Utilities & Transmission Equity value per share							\$41.58	\$44.37	\$48.04
Less: Recourse FES Obligations (Sale Leaseback)							(\$3,033)	(\$812)	(\$812)
Less: Other Parent Sale Leasebacks							(\$388)	(\$388)	(\$388)
Less: Parent Notes (12/31)							(\$4,200)	(\$4,200)	(\$4,200)
Plus: FES Cash Distributions to Parent (NPV 2017-2020), -approx							\$0	\$1,281	\$1,722
Parent/FES Drag per Share							(\$17.97)	(\$9.71)	(\$8.49)
FirstEnergy Combined (Regulated & FES) Equity Value							\$24.00	\$35.00	\$40.00

Source: Company filings, FactSet, UBS estimates

# ITC Holdings Corp.

Fortis is waiting until it secures the minority interest stake in ITC before making the key FERC and state regulatory applications so no material updates are expected until that point in time. We read the FERC decision compelling ITC Midwest to simulate the impact of bonus depreciation and refund customers as a significant negative. No further progress appears to have been made on Lake Erie since the last call based on public data and management indicated that they might not be in a position to provide more definitive details until 2Q or later in 2016.

For additional context, please refer links to relevant recent reports below:

[4/13/16 Electing to Get a Bonus?](#)

[2/23/16 Searching For Clues in Regulated M&A](#)

[2/10/16 Fortisified](#)

[12/1/15 Exploring an Exit](#)

[9/30/15 Perfect Storm](#)

[6/10/15 Lining Up Lake Erie](#)

[6/2/15 Heading Down the FERC Vortex?](#)

[5/22/15 A \(Deficient\) Letter from Washington](#)

[4/1/15 Is The Glass Half Empty?](#)

[12/19/14 The SMID Bid: The Context for Regulated M&A](#)

## What are the pivotal question for ITC?

### **What is the status of the Fortis acquisition?**

- **Fortis acquisition of ITC announced in February:** Canadian utility Fortis (TSX: FTS) announced a deal to acquire ITC Holdings (ITC) for \$6.9B of equity (\$22.57 cash plus 0.7520 FTS shares) and the assumption of \$4.4B consolidated ITC debt that would ultimately create a ~\$30B EV utility (~65% FTS + ~35% ITC). Based on FTS price when the deal was announced (~\$41.40/sh, a 52-week high) this represented a 19.3x 2017E P/E, a 17% premium to the average regulated utility at the time. Fortis declined sharply following the announcement but has recovered to trade at ~\$39-40/sh.
- **Finding a minority investor the critical datapoint to move the process forward:** Fortis plans to issue \$2Bn of US dollar denominated debt (2Q-3Q) and is still undertaking the process to locate a minority investor for 15~20% of ITC, which Fortis intends to raise \$1.0-\$1.4Bn USD. An update on the minority interest process is expected by the end of 2Q16; however, the deal is not contingent on finding another investor. If Fortis is unable to come to terms with a third party for a minority stake then management will issue additional FTS equity and debt. The majority of the equity in the deal is in the form of Fortis shares (0.7520 FTS shares for each 1 share of ITC) Fortis intends to finance the transaction such that it retains its investment grade credit ratings.
- **Regulatory approval process expected to begin in June at the latest:** The formal acquisition applications will not be filed until the joint venture investment is in place but Fortis stated that it will file the applications "no later than 120 days from the time of the announcement" [February 9] implies that the applications will be made by June 8<sup>th</sup>. The FERC has 180 days to review the transaction indicating a possible decision by early December, consistent with the guided close period of late 2016. Other federal approvals include DOJ and

State regulatory approvals are required in IL, KS, MO, OK and WI (not in IA, MI or MN). Only FERC has any direct rate authority over ITC

CFIUS in addition to shareholder votes. Fortis expects to require state approval from Illinois, Kansas, Missouri, Oklahoma, and Wisconsin but not Iowa, Michigan, or Minnesota.

### How are FERC transmission economics trending?

- **Can ITC retain the independence adder through a deal? It depends on the circumstances of the buyer:** This remains among the most hotly debated points among investors, with our initial understanding suggesting that any likely buyer would indeed trigger ITC to lose its reduced 50bp independence adder (used to be 100bp). However, upon further discussions with industry participants, we emphasize several appear to suggest that a company (such as ITC) could potentially keep this adder if the acquiring entity was not operating in a given RTO. While this suggestion from peers has yet to be tested before FERC, this could indicate that ITC could potentially retain the ROE incentive if the minority owner does not operate in -Midwest Independent System Operator (MISO).
- **Latest FERC MtM analysis highlights 10.9% ROE as an outlier:** Following the [initial decision](#) (ID) in the pending FERC regulated transmission base ROE complaints released on 3/22 we have prepared our latest mark-to-market using the consistent New England case methodology (midpoint of the upper half i.e. 75<sup>th</sup> percentile). Our analysis indicates a ~9.5% 75<sup>th</sup> percentile ROE, largely consistent with the outcome in the EL13-33-002 case (9.59% FERC base ROE). In our analysis we exclude ITC and TE (pending M&A) and adjust for GXP's "illogically-derived" IBES growth rate (9.1% vs. 4-5% guidance 2016-2020), which has a ~105bp negative impact. The latest New England ROE FERC case (EL 14-86-000) for the Nov'14-April '15 period still *includes* both ITC and TE (both pending acquisition targets), which causes what we consider an outlier outcome versus what we perceive as a longer-term declining trend in utility ROEs.
- **How significant is the impact of "anomalous conditions"?:** We estimate an 8.6% ROE at the midpoint, 88bp below the 75<sup>th</sup> percentile, and representing a level that is likely at a discount to state-level authorized returns in many jurisdictions. The wider question continues to be how FERC will continue its objective of incentivizing transmission as the spread declines. We wouldn't doubt a new approach emerges in subsequent ROE revisions to address this desire to keep FERC above states. We note that there has recently been a longer than normal lag in the refund period, at 7 months vs. 5 months normally.

A risk to an acquisition of ITC is the potential loss of the 50bp adder for being an independent company. Based upon discussions with industry participants we emphasize that it remains a possibility that a transmission operator outside of Midwest Independent System Operator (MISO) could retain the independence adder

ITC stated that the latest FERC decision was a positive datapoint

**Figure 151: Updated FERC ROE Mark-to-Market Analysis – The Latest Revision Down**

ROE Analysis Summary	Low	Midpoint	High	FERC "Upper Midpt" 75th %	Ranked 75th %
Zone of Reasonableness (Original)	7.03	9.39	11.74	10.57	9.77
Zone of Reasonableness (1/4 GDP Weight)	6.97	9.51	12.05	10.79	9.84
Zone of Reasonableness (UBSe MTM 8/19/14)	7.14	10.25	13.35	11.80	9.65
Zone of Reasonableness (UBSe MTM 10/22/14)	6.77	9.28	11.80	10.54	10.25
Zone of Reasonableness (UBSe MTM 1/26/15)	5.96	8.81	11.65	10.23	10.11
Zone of Reasonableness (UBSe MTM 3/10/15)	6.30	8.68	11.07	9.87	9.32
Zone of Reasonableness (UBSe MTM 4/22/15)	6.22	8.64	11.05	9.84	9.36
Zone of Reasonableness (UBSe MTM 11/12/15)	6.31	8.60	10.89	9.74	9.41
<b>Zone of Reasonableness (UBSe MTM 3/23/16)</b>	<b>6.87</b>	<b>8.63</b>	<b>10.39</b>	<b>9.51</b>	<b>9.45</b>
Westar Settlement	July 2015			9.80	
FirstEnergy 2016 Settlement (Pre-Adder)	July 2015			9.88	
Transco NY Settlement	Nov 2015			9.0-9.5	
EL13-33-002 ALJ Initial Decision	Jan 2013-Mar 2014		10.42	9.59	
EL14-86-000 ALJ Initial Decision	Aug 2014-Sept 2015		12.19	10.90	
Increase/(Decrease) latest MTM from Orig	(0.16)	(0.75)	(1.35)	(1.05)	(0.32)

Source: FERC, company filings, FactSet, Yahoo! Finance, UBS estimates

[Please click here for further details on our transmission ROE analysis.](#)

- **ITC ordered to refund impact of bonus depreciation for 2015 as decision not to elect bonus depreciation was "imprudent"....:** On March 11<sup>th</sup> the FERC ruled partially in favor of Alliant's Interstate Power and Light subsidiary (IPL) in its challenge against ITC's subsidiary (ITC Midwest). Specifically the FERC ruled that ITC did not justify its decision to not elect bonus depreciation in 2015. ITC will recalculate the rates at this subsidiary to simulate the impact of bonus depreciation and issue a refund to customers. Based on IPL's calculation the impact on 2015's revenue requirement was +\$18Mn (\$0.07/sh after-tax). ITC Midwest represents 35-40% of ITC forecasted ratebase.

"Here, we are making a determination that ITC Midwest's decision, through its corporate parent, to make a tax election to forgo zero-cost capital to increase its ratebase and revenue requirement has been shown to be imprudent and results in unjust and unreasonable transmission rates... The record herein provides that by opting out of bonus depreciation ITC Midwest, through its corporate parent, has chosen to forgo cost-free capital solely to inflate its ratebase and revenue requirements." – FERC March 11, 2016

- **...FERC does not require ITC to elect bonus depreciation going forward:** The FERC ruling only applies to 2015 and is neither retroactive nor automatically applicable to future periods. For prior periods the FERC does not want to intervene in IRS matters as ITC has already filed its taxes to not elect bonus depreciation. For future periods the FERC stated that rates are assumed to be prudent until proved imprudent; therefore, if ITC does not elect bonus depreciation in the future it is open to challenge. For example, if ITC is able to prove a justification for its decision in 2016+ its rates can stand as prudent; however, the rationale provided in 2015 was rejected. It appears to us that if a utility has a valid reason for not electing bonus depreciation (ex. the loss of other tax benefits), that appears to be a sound justification. Absent a change in circumstances for ITC we would expect FERC to again scrutinize ITC if it does not elect bonus depreciation.

**Alliant had requested that the FERC compel ITC to get a private letter ruling for prior periods but that was denied**

ITC has not determined whether it will elect bonus depreciation following the recent extension but has not historically elected it. Since ITC does not have to

file state ratecases the company enjoys a lower degree of local regulatory scrutiny than peers.

“Although based on the record in this proceeding we have found ITC Midwest’s decision, via its corporate parent, to opt out of bonus depreciation to have been imprudent, we cannot presume that such a decision would necessarily be imprudent in future years.” – FERC March 11, 2016

[Please click here for the full order: Docket ER15-1250-000.](#)

[Further thoughts are available in our note ‘Electing to Get a Bonus?’](#)

## Valuation: Increasing price target to \$46 from \$39 on Fortis recovery

Valuation is based on Fortis acquisition offer for ITC. When announcing the transaction Fortis disclosed a \$44.90/sh offer price based on \$22.57 USD cash and 0.7520 shares of Fortis per share of ITC Holdings. At the close of the announcement date Fortis closed at \$26.88/sh USD and is now trading at ~\$31/sh USD.

**Figure 152: Updated ITC Valuation**

Base Case: Takeout Price Update Calculation	
FTS-TSE Price (C\$)	Cd\$40.16
FTS-TSE Price (USD)	USd\$31.26
ITC Price	USd\$43.39
Cash consideration	\$22.57
FTS Stock	0.7520
<b>Current takeout price</b>	<b>\$46.08</b>

Source: Company filings, FactSet, UBS estimates

# NextEra Energy

Investor focus has been on the Oncor process in Texas lately but the most significant datapoint on the upcoming call will relate to the wind/solar unregulated capex and how much equity is required in 2016. We expect minimal equity with NEE instead relying on secured project debt to 'bridge the gap'. HE is another upcoming topic of interest and we believe the market may be underestimating the possibility of the transaction getting done.

We forecast NEE reporting adjusted 1Q16 EPS of **\$1.56**, well above consensus (\$1.35) as the comparable quarter was negatively impacted by below-average wind generation (-\$0.11 estimate based on -13% lower wind generation versus normal). Although corporate G&A and dilution will offset much of the organic growth expected, assuming normal wind we anticipate a strong recovery for NEE. We continue to expect the utility Florida Power & Light (FPL) to continue earning its ROE with ~\$265Mn of depreciation credits available for use at year-end.

Consensus expects a decline YoY for NEE but the drivers point to an improvement versus a weak 1Q15 comp

Figure 153: NEE 1Q16E Earnings Walk

NextEra Energy 1Q16 Earnings Walk	EPS
1Q15A Adjusted EPS	\$1.41
<b>FPL: Targeting Earning 10.5-11.5% ROE</b>	
Weather vs Normal in 1Q15	(0.02)
Weather vs Normal in 1Q16	0.02
O&M: Project Momentum	0.02
Depreciation Reserve Amortization	(0.03)
New Investments	0.06
Wholesale	0.00
Incentive Mechanism	0.00
Sales & Usage Impact: -0.5% to Flat	(0.01)
<b>Energy Resources</b>	
Customer Supply & Trading	0.04
New Investment	0.09
Existing Assets	
Return to Normal Wind (87% in 1Q15)	0.11
Impact of Wind in the Quarter	(0.01)
Refueling Outages and Other Impacts	(0.02)
Gas Infrastructure	0.01
Asset Sales	0.00
Corporate G&A and Other	(0.06)
Dilution	(0.05)
<b>1Q16E Adjusted EPS</b>	<b>\$1.56</b>
<b>1Q16 Consensus</b>	<b>\$1.35</b>
<b>2016 UBSe EPS</b>	<b>\$6.18</b>
<b>2016 Consensus</b>	<b>\$6.15</b>
<b>2016 Guidance</b>	<b>\$5.85-\$6.35</b>

Source: Company filings, FactSet, UBS estimates

*For additional context, please refer links to relevant recent reports below:*

[4/15/16 How about a Nice Hawaiian Punch](#)  
[3/29/16 More Questions Surface Over Oncor](#)  
[3/22/16 Is Oncor Slipping Away?](#)  
[2/11/16 Growing Renewables With or Without CPP \(Management Meetings\)](#)  
[2/1/16 Beating Guidance Once Again](#)  
[11/30/15 EFH Lassoed Texas Gas Plants](#)  
[11/23/15 Still Kicking the Tires in Texas](#)  
[10/29/15 Reinvesting in the NEE Family](#)  
[9/17/15 Still The Industry Leader](#)  
[8/30/15 Ramping up Expectations](#)  
  
[4/30/15 A Shining Star](#)  
[3/12/15 Pure Squeezed Sunshine \(Analyst Day Note\)](#)

## **What are the pivotal questions for NEE?**

### **Will NextEra complete the pending Hawaiian Electric transaction?**

- **Getting close to a decision with closing briefs May 2<sup>nd</sup> and "walk away" June 3<sup>rd</sup>:** With the June 3<sup>rd</sup> deadline approaching after which either NEE or HE can walk away from the merger agreement, we see the current price for HE as indicating low expectation of the deal getting completed. Currently both Governor Ige and current Hawaii Public Utilities Commission (PUC) Chairman Iwase have made well publicized statements against the merger. However, as described below, it's not clear that the deal is outside of the Hawaiian standard. It's also possible that beside an outright approval or disapproval, the commission could approve but with additional conditions. If the conditions proved onerous enough, NEE could ultimately reject the proposal. We think the least attractive result would be if a "no decision" situation led to an ambiguous "implied" rejection and walkaway on June 3<sup>rd</sup>.
- **Hawaii standard is "fit, willing and able" with no requirement for net benefits:** The Governor has framed his opposition to NEE as "not a good fit" for the state's energy goals, despite NEE's much larger balance sheet and status as one of the largest renewable energy developers in North America. However, with the state only requiring a "fit, willing and able" standard, the possibility of approval in spite of the Governor's opposition cannot be excluded. Further, we note the recent approval of HE Gas' LNG petition despite initial statement seemingly opposing LNG imports.
- **What does this mean for NEE? Modest value plus illustrates execution potential:** With limited EPS accretion under its initially disclosed outlook, we estimate the deal is worth ~\$1-2/sh off full run-rate uplift. While management has never explicitly shared both its prospective ratebase growth (including the latest PSIP spending program presumably) alongside cost cuts to achieve its ROE, this could prove accretive to utility growth. The focus remains on expanding its regulated utilities alongside its accelerating renewables efforts.  
[Please click here for the full docket.](#)

With HE having fulfilled its commitment to achieving shareholder approvals, the breakup fee in case of regulatory rejection would be \$90Mn from NEE to HE

## How much equity is expected to be needed in 2016?

- **Not expecting to issue equity in 2016 but if necessary, needs will be 'modest':** As mentioned previously, management will provide a full update on its capital and financing needs on the 1Q16 earnings call but NEE currently does not expect material capital needs. While a bit ambiguous on whether asset 'recycling' was part of the base financing plan, we emphasize this appears to be a small part of overall plan if so. We detail factors influencing the need for equity:
  - Sale of the TX gas plants to EFH for \$1.6Bn (~\$456Mn is the net cash flow when adjusting for cash on hand and project financing). The transaction closed on April 4<sup>th</sup> and the gain will be excluded from 2Q16 adjusted earnings.
  - Further potential asset merchant asset sales? We believe its merchant wind portfolio in West Texas could well be the next portfolio of assets targeted, as well as its remaining one-off thermal assets (no nuclear sales are anticipated) in PJM and New England. While its last review of the New England portfolio did *not* result in a sale, management has indicated that further non-core asset sales are possible to reduce equity needs. Unregulated conventional assets include Marcus Hook CCGT (847MW in PA), Sayreville Cogeneration (160MW net ownership in NJ), and Bellingham Cogeneration (168MW in MA). The Cogeneration assets have PPAs with the local utilities.
    - Wind assets in other markets running off contract could be eligible for sale; these are likely quite small outside of Texas.
  - Adding leverage to unencumbered assets – this appears to be the most significant wildcard. Management has 6-12 projects on the balance sheet that do not have leverage as of YE15 and depending on the characteristics of the assets management would be comfortable adding 70% leverage (project finance) to the contracted assets which would help reduce capital needs. Assuming ~70% financing against a ~\$1,200/kW value (depending on the depreciated life), suggests \$500-800 Mn by our estimates. This remains the primary alternative source of incremental capital to avoid equity in 2016.
  - The extension of bonus depreciation should also help reduce the long-term financing needs.
  - Extension of the renewables tax credits, which should drive positive capex revisions and the potential for "good" growth equity issuances
  - Net capital activity between NEP (drop-downs less purchasing NEP shares in the market)
- **If equity is needed, we would expect additional forward units:** NextEra's historical equity forward unit sales have settled after three years and shares are not typically recognized for GAAP dilution purposes until settlement. In September NextEra completed a \$700Mn equity forward which settles in September 2018 between \$95.35/sh-\$114.42/sh. For example based upon this latest financing there will only be one quarter of additional dilution in 2018. Below we summarize the forward equity unit offerings done over the past few years. We emphasize that despite this additional equity issuance, management remains committed to its previously communicated earnings guidance ranges.

Regardless if management has to issue equity, it is confident in its EPS guidance

If NEE does have to issue equity to support its renewables build-out, we think this would be accretive growth equity given the number of opportunities available for management

While 2016 EPS guidance reflects this dilution already in the range, we see this as a technical weighing on shares. For example NEE shares underperformed when NEE hosted a financing call in 2015 discussing another slug of equity

We emphasize that despite the September 2015 equity issuance, management remains committed to its previously communicated earnings guidance ranges

**Figure 154: Summary of NEE Forward Equity Sales**

Unit Class	\$Mn	Shares (Mn)	Issue Date
2012 May	\$600	7.9	June 2015
2012 Sept	\$650	8.2	September 2015
2013 Sept	\$500	5.5	September 2016
2015 Sept	\$700	6.7	September 2018

Source: Company filings, UBS

### How will management revise its near-term Energy Resources capital budget and what are the prospects for future growth?

- **NextEra Energy Resource – Positioned to gain market share:** NextEra sought to reassure investors that it will not sacrifice margin in order to achieve its objective to grow its development efforts by up to double. In fact, NEE has not observed a material change in the return profile for its renewable projects over the last 5-10 years despite changes to the competitive landscape. The goal to double the development business is not a near-term goal and is likely going to be observed in the 2018-2020 timeframe.
- **How will 2015/2016 compare to 2017/2018?** NextEra Energy Resources (NEER) finished 2015 on a strong note NEER signed another 285MW for 2015/2016 (~80MW U.S. solar with the remainder U.S. wind) and indicated that its 2016 plan is essentially complete but there are one or two possible incremental opportunities. There is ~236MW of additional renewables secured for 2016 but management is waiting until April (1Q16 earnings call) to provide a more detailed update on 2017/2018 expectations. When last updated with 3Q15 results there was 1.2-1.4GW of US renewables in the pipeline. Currently NEE has disclosed ~236MW of projects secured for 2017+ but we expect NEE to continue its string of success going forward.

**Management expects that 2018 will be a ‘huge year’ for wind given the PTC step-down but the outlook is less clear for 2017 with many customers pulling orders forward into 2016 to beat the original ITC cliff.**

**Figure 155: Analysis of NEER Renewables Backlog (MW)**

Analysis of NEER Renewables Backlog (MW)			
2015/2016	4Q14 Update	4Q15 Update	Change
US Wind	980	2,397	1,417
US Solar	960	1,385	425
Canadian Wind	175	174	(1)
<b>Total</b>	<b>2,115</b>	<b>3,956</b>	<b>1,841</b>
<b>New renewables signed in past year</b>			<b>2,100</b>
<b>Contracted for 2017+</b>			<b>236</b>

Source: Company filings

- **Competition for wind development has been declining:** NEER has observed a decrease in competition but has not seen any real increase in % margins. Many of its main competitors from five years ago are no longer in the business although there have been some names that continue to appear (ex. Invenergy). For example, Solar competition continues to be healthy with lower barriers to entry but NEER still touts its advantages over smaller developers.

Prior to the ITC/PTC extensions NextEra stated that it was “significantly increasing” its renewables development budget (not capex) which could potentially double through ~2019 with the objective of a proportional increase in capacity

Management signed 2.1GW of new renewable projects in the past year, with the vast majority being US wind projects

NEER had 1.2-1.4GW of 2017/2018 pipeline as of 3Q15 – an update is expected in April

We believe that the financial stress at SunEdison and recent management changes have impacted the FirstWind subsidiary’s ability to compete in the market, a benefit for NEER and others

- **Further, what does a doubling represent?** We estimate this could represent north of 2GWs/yr in total renewable development off a historic baseline of 1.1-1.2GW/yr in organic dev through 2013. While already executing at this pace in 2016, the key question is whether 2017 can meet this level given the acceleration of procurement into 2016 that has already occurred.

**Can the development opportunities (up to) double?: NextEra has doubled its development efforts in the past and it believes it can do it again**

The biggest takeaway from our February meeting with NextEra is that its renewable development business is well positioned to gain a larger share of the growing market, even without the Clean Power Plan. Prior to the Supreme Court issuing a stay regarding Clean Power Plan implementation, management observed interest from parties that wanted to get a head-start on compliance. The CPP and increasing renewable portfolio standards would certainly be tailwinds to help support growth but management sees interest in projects primarily based on economic rather than environmental considerations. For example management provided a few illustrative datapoints:

- Midwestern Wind PPAs signed at ~\$20/MWh in 2015
- Michigan wind in the \$40/MWh range vs. \$60-\$70/MWh earlier in the decade
- California Solar PPAs for 2016 delivery have declined to \$50-\$55/MWh in 2015 from \$80-\$90 in 2011. Furthermore, management expects these prices to be a lot lower in 2020 than even \$50/MWh. Management notes the latest RFP is ongoing in the state for 2020 at present.

#### How are the customers changing? **More C&I and more ratebasing requests**

One of the more significant changes for NEER over the years has been the rise of non-traditional utility customers as counterparties with companies pursuing green energy for both social and economic reasons. A prime example is data centers which continue to experience strong growth and desire to show a green transformation. *We emphasize this trend towards long-term PPAs directly with C&I customers is part of a growing and consistent trend we've heard through much of 2H15. We emphasize this is particularly true in the Texas market where a large liquid and economic market remains.*

There has been an increase in the volume of utilities requesting ownership (i.e. ratebasing) of renewable projects but NextEra's objective continues to be 'build-and-hold' to the extent possible. For example Westar Energy (WR) announced a 200MW purchased power agreement with NEER's Kingman Wind Energy Center with an option to purchase 100MW prior to substantial completion.

**NEE will work with its customers to arrive at favorable outcomes for both parties**

We expect this to be a hot topic as utilities will likely attempt to argue that the ratebase solution is better assuming that power prices increase in the future and push this solution as a 'hedge' versus pure PPAs. We note that NextEra has worked extensively with Xcel in Colorado and given their relationship could be more receptive to offering a greater ratebase percentage. Having said that, it appears far less likely to NEE and us that solar will be ratebased as regulated entities have to normalize the ITC; this reduces the upfront cash proceeds and all else equal should allow third-party developers to offer lower cost PPAs. We see NEE treating the wind development business as an ongoing development effort for them – and will treat those requesting to pursue wind development flip projects back to the ratebase entity as one of a number of products that NEE can deliver.

## What is the outlook for growth at the core Florida utility?

- **Focus turns to FPL ratecase – hoping for status quo:** NEE subsidiary Florida Power & Light (FPL) formally in mid-March a \$1.3Bn four-year request (January 2017 - December 2020) with the Florida PSC for new base rates that would be implemented in 2017 with an 11.5% ROE midpoint (including 50bp premium for historical “exemplary performance”). We believe that simply maintaining the ability to earn the same ROE will be perceived positively by the market. FPL’s current ROE is established at 10.5%, with an allowed ROE band of +/- 100bp and the Company has historically earned at the top-end of the range, principally predicated on use of legacy depreciation credits.

Management expects to seek a premium ROE based on its track record for efficient performance

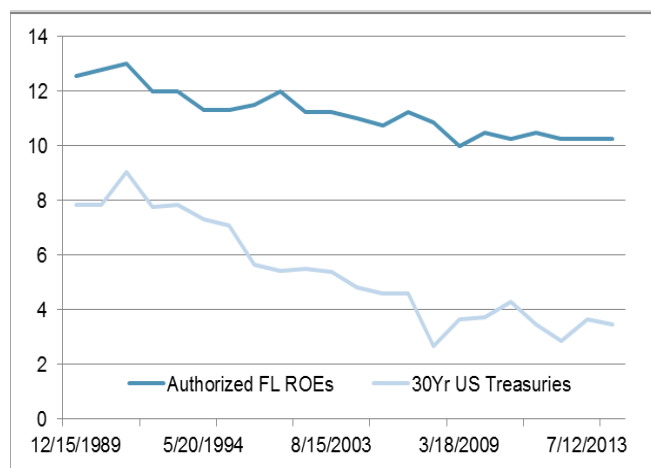
While management will push for a premium ROE (10.5%-12.5% range), if NEE is able to just keep its ROE we believe that would be received favorably by investors

Figure 156: FPL Preliminary Rate Request

Year	Revenue Req. (\$Mn)	Inflation
2017	\$866	8.2%
2018	\$262	2.3%
2019	\$209	1.7%
2020	\$0	0.0%
<b>Total</b>	<b>1337</b>	<b>12.2%</b>
<b>Average</b>	<b>\$334</b>	<b>3.1%</b>
2013-2015 Avg. Requested ROE		10.50%
2013-2015 Avg. Approved ROE		9.86%
Current Avg. Pending Requested ROE		10.45%
Current FPL Requested ROE		11.50%

Source: Company filings, SNL Energy, UBS

Figure 157: Authorized Florida ROEs vs. 30Yr US Treasuries



Source: SNL Energy, FactSet

### Why are we not overly concerned about the case?

- (1) FPL’s 11.5% request is above-average nationally but Florida has historically had above-average ROEs which have not been below 10%. From 2013-2015 Florida has had a 10.25% ROE authorized ROE, a 40bp premium over other states. If this trend holds we could see ROE slippage to 10.25%, still a decent outcome. Interest rates are also only down 20bp since the 2012 ratecase settlement (2.4% 10-year at the time vs. ~2.20% today).
- (2) Bill increases under the proposed plan largely tracking historical inflation based on NEE’s revenue request (~3-4%).
- (3) NEE has had top-tier performance and continues to have the lowest bills in the state.
- (4) We note that four of the five sitting commissioners today were present for the last 2012 ratecase, suggesting there is continuity in the understanding of key issues before the commission and familiarity with management’s track record on costs.

Even with a satisfactory **ratecase** outcome, NEE might not earn at the top of its ROE band initially as management expects it could take a couple years to drive O&M savings yet again as the latest round of savings will be recaptured in the ratecase.

While not a real risk to the story, the forthcoming case does require another depreciation study and management estimated that this will drive expense \$200Mn higher, thus forcing up the aggregate cash impact of the rate request. While ultimately a straightforward process, this could seemingly attract attention.

What is the preliminary timeframe expected? Summer/Fall

**Management expects a ten month timeline to have new rates in effect for January 2017 but initiated the process a bit earlier than usual to provide enough leeway in the schedule for any hurricane season related timing disruptions.**

- 2Q16: Hearings focused on FPL's historical operational performance – this will be key in assessing the validity of an ROE performance incentive
- June/July: Intervenors and PSC Staff file testimony while FPL has the opportunity to present rebuttal testimony in response
- August 22-September 2: Broader rate hearings
- 4Q16: Final PSC decision
- January 2017: New rates effective

Is a settlement possible? Management reiterated its openness in our meeting.

With few controversial issues we think a **ratecase** settlement is a distinct possibility again. FPL reiterated that it is open to another multi-year settlement but four years would likely be the longest duration it was comfortable with given the interest rate. If a settlement is likely it would likely occur in early-to-mid 3Q15 (July/August), prior to hearings. In the last **ratecase** FPL (Docket 120015) offered a settlement in mid-August 2012.

**NEE has a track record of settling ratecases: 5 multi-year settlements have been struck over the last 17-years**

How will the Office of Public Counsel influence the process?

In the previous **ratecase** the Florida Office of Public Counsel (Public Counsel) was not a party to the settlement and challenged the settlement to the Florida Supreme Court making a litany of arguments. The Florida Supreme Court issued a lengthy opinion denying the Public Counsel's arguments. NextEra is hopeful that it can have productive conversation with the Public Counsel as it did on the recent Cedar Bay settlement.

- **Solid customer and usage growth in 4Q but still expecting a longer-term decline:** NEE reported +2.1% weather normalized sales growth during 4Q15 which was driven by +140bp of customer growth and +70bp of usage growth, breaking a trend of disappointing usage in recent quarters. Despite a strong 4Q, FY15 still saw a -30bp decline in customer usage. With 3Q15 results NEE management reduced its forward looking weather-normalized guidance to a range of negative 0.50% to 0.0% from positive +0.50% in 2016/2017 and flat in 2018. The guidance was confirmed on the 4Q call. This was certainly a negative (particularly given the reversal from March 2015's Analyst Day guidance) but we still expect FPL to earn near the top-end of 9.5-11.5% allowed ROE band. Management's guidance is for the top-half of the range in 2016 but we expect FPL to continue its streak of top-performance, particularly with the aid of the \$263Mn depreciation reserve amortization. For context in the previous three years FPL collectively utilized \$107Mn.

**Declining per customer usage is troublesome but (1) customer growth outweighs and (2) 2016 is insulated due to the healthy reserve amortization available**

Customer usage in the FPL territory has trended lower but management emphasized the strength and diversity of the local Florida economy supports continued growth. Although FPL expects to be compliant with the Clean Power Plan in a 2030 scenario (i.e. the utility is compliant today and expects to continue to be even when accounting for customer growth with associated new generation). **Even if sales remain largely stagnant, management sees significant capex opportunities for smart grid technology and storm hardening with the latter having a greater importance given the propensity for hurricanes in the territory.** If customer growth remains strong FPL anticipates meeting the increasingly load demands via renewable generation to the best extent possible, leveraging the experiences from its ratebase projects under construction at FPL (as well as naturally the NEER expertise). As a reminder, the first three utility scale projects in Florida were all done at advantaged sites which made the economics more attractive.

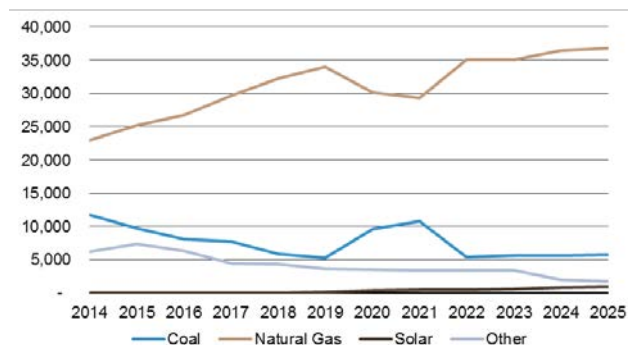
**FPL intends to be very aggressive on growing solar ratebase in FPL and has no intentions of having its unregulated subsidiary participate in the state as to avoid a conflict**

Further diversification from CPP? With FPL largely achieving its CPP targets *already*, the utility growth story is de-correlated from peers in the industry and remains a hedge to investments at the NEER-side of the business to enable renewable oriented growth.

- **Drilling down into Florida utilities plans:** The Florida utilities filed their ten-year site plans on April 1<sup>st</sup> [\[details here\]](#) and conventional generation is expected to dominate the fuel mix. Solar is expected to represent <3% of the generation for each of Duke Energy Florida, Florida Power & Light, and Gulf Power, respectively. Duke plans to add 550MW of solar PV while **NextEra is targeting 633MW (300MW incremental by 2021 to the ~225MW previously announced to be in-service by YE16)**. While the growth in renewables is significant, with limited net load growth forecasted 2015A-2025E (20-70bp) there is a natural constraint on deployment in the absence of new environmental standards.

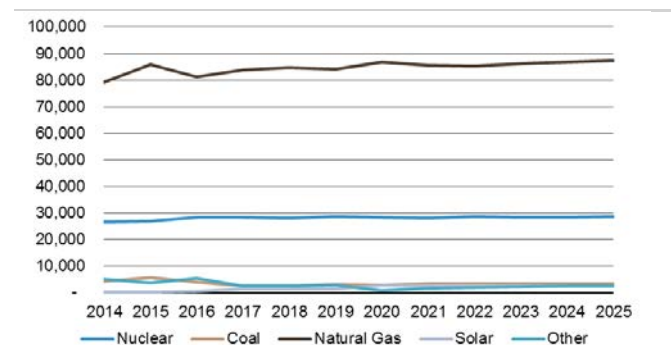
**DUK and NEE project ~150bp customer growth over the ten year period but only ~50bp of net load expansion**

**Figure 158: Duke Energy Florida Forecasted Energy Sources (GWh)**



Source: Company filings

**Figure 159: Florida Power & Light Forecasted Energy Sources (GWh)**



Source: Company filings

- **On residential solar the best defense is a good offense:** The Solar Energy Industries Association ([SEIA](#)) ranks Florida as #3 in the US for "rooftop solar potential" but continues to have very little by way of residential solar which management attributes to its low average bill that makes the return profile for residential less attractive. For example, in 2015 the average residential bill was \$97/month versus \$137/month nationally per EEI. FPL forecasts its average bill falling to \$93 in 2016 before growing to \$107 by 2020 in its **ratecase** disclosures discussed above.

On March 31<sup>st</sup> the Florida Supreme Court voted 4-3 in favor of the Consumers for Smart Solar ballot initiative which is Solar supported by the local investor owned utilities. Consumers for Smart Solar was able to obtain enough valid signatures to meet inclusion on the ballot (~720K signatures vs. ~683K requirement) and the Supreme Court vote was regarding the validity of the ballot initiative rather than opining on the specific ballot. While there is significant rhetoric in the media, NextEra's objective is to avoid the cross customer subsidization that has occurred in other states. If there is a Florida constitutional amendment addressing the subsidization issue, the actual terms would likely need to be decided by the Florida Public Service Commission (PSC). We believe this could take the form of a lower net metering rate (ex. avoided cost) or higher charges – both aspects that the pro-solar groups would likely oppose as one the Alliance for Solar Choice's stated goals is "protecting net metering".

- **Wholesale opportunity being tapped but still room for growth:** FPL already provides wholesale power to other electric providers in the state and represents approximately 60-65% of the generation in the state despite having ~50% of the customer base. There could be opportunities for further wholesale opportunities in the future but management did not talk up this area. Munis and co-ops could opt to contract with FPL for economic reasons (lowest bills in the state) and/or environmental reasons (Clean Power Plan compliance). In a recent FERC filing FPL requested market-based rate authority in Peninsular Florida (east of the Apalachicola River) which would extend the rights that it has outside of Peninsular Florida. (FERC Docket ER16-628)
- **Additional scrutiny on gas ratebasing:** On April 3<sup>rd</sup> the Wall Street Journal ran an article highlighted that utility fuel hedging programs have generated significant losses as utilities incorrectly forecasted natural gas pricing trends and relied on overly simplistic programs. For example Florida Power & Light overpaid by \$6Bn from 2002-2016 as a result of its hedging program. NextEra's first regulated natural gas reserve pilot investment was expected to cost customers in 2015 rather than generate savings and the total savings over the life of the asset have been reduced by 50% already. With this backdrop, we continue to see a low probability of further natural gas ratebasing. Furthermore there are likely few parties willing to sell at these current prices instead believing that pricing will recover. While a continued modest negative for NEE, we do not believe investors have embedded any real contribution from gas ratebasing. (Florida PSC Docket 150001-EI)

The added risk of future solar adoption adds to the risks around hedging gas on a long-term basis via reserve ratebasing

Further details are available in our note ['The Battle Over The South'; focusing on solar vs. gas in the South](#)

## What does management think about further M&A?

- **Still receptive to acquisitions but price has to be right:** At our March 2016 conference management commented that it is challenging to extract meaningful accretion from regulated acquisitions when paying a significant premium but it continues to be open to the idea if the right opportunity presents itself. Echoing comments from the March 2015 Analyst Day, the company believes it has a very transferable skill set on utility operations (cost control, generation planning, etc.) that it could bring to other utilities. The company's preference in M&A would be to pursue utilities that are not earning at their allowed ROEs and/or have opportunities to extract costs to create headroom for capital spending opportunities. If NEE were to pursue a transaction it would not want to lose its BBB senior unsecured S&P credit rating. Bringing the conversation back to the tangible, management repeated that it views Oncor as a solid asset based upon its disclosures but will remain disciplined regarding how much it can pay for it if the current Hunt-led proposal is ultimately unsuccessful.

Factors that management considers:

- Ability to reduce O&M
- Opportunity to deploy more capital with the headroom created from less O&M
- Under-earning
- Maintain or strengthen the balance sheet

## Maintaining our EPS Estimates and Valuation

Below we present our adjusted EPS estimates and valuation. Given how significant the 1Q16 update is expected to be with a multi-year view of development capex following the renewables tax credit extension, we look to provide more details update at that point. Although we expect a positive revision we do not anticipate an increase to the *6-8% long-term EPS growth target*. Management indicated that the early revision already contemplated an acceleration of renewables spending and we suspect an extension of the runway is more likely.

Figure 160: NextEra EPS Estimates

EPS - Segments	2013A	2014A	2015A	2016E	2017E	2018E
FP&L	3.16	3.45	3.63	3.80	3.91	3.89
NEER	1.83	1.89	2.04	2.24	2.41	2.68
Corporate & Other	(0.02)	(0.04)	0.06	0.14	0.18	0.34
<b>Total UBSe</b>	<b>4.97</b>	<b>5.30</b>	<b>5.72</b>	<b>6.18</b>	<b>6.50</b>	<b>6.92</b>
UBSe (Prior)	4.97	5.30	5.72	6.18	6.50	6.92
<b>Consensus</b>		<b>5.30</b>	<b>5.66</b>	<b>6.15</b>	<b>6.54</b>	<b>6.97</b>
<b>Company Guidance</b>			<b>\$5.40-\$5.70</b>	<b>\$5.85-\$6.35</b>		<b>\$6.60-\$7.10</b>

Source: Company filings, FactSet, UBS estimates

Our valuation is based on a 2017E sum-of-the-parts analysis.

Figure 161: NEE Sum-of-the-Parts Valuation

2017E Adj. EBITDA		EV/EBITDA & P/E Multiple			Enterprise Value		
Energy Resources		Low	Base	High	Low	Base	High
Traditional Generation	948	8.0x	9.0x	10.0x	7,583	8,531	9,479
Wind (Total)	1,077	9.0x	10.0x	11.0x	9,697	10,774	11,851
Hedges (Texas 'Merchant' Wind)	(61)	9.0x	10.0x	11.0x	(552)	(613)	(675)
Tax Credits (PTC)	939	7.0x	8.0x	9.0x	6,574	7,513	8,452
Less NEP Initial Wind Assets	(175)	9.0x	10.0x	11.0x	(1,578)	(1,753)	(1,928)
Solar (Total), excl ITC	324	9.0x	10.0x	11.0x	2,915	3,239	3,563
Less NEP Initial Solar Assets	(88)	9.0x	10.0x	11.0x	(788)	(875)	(963)
Gas Infrastructure	363	7.0x	8.0x	9.0x	2,538	2,900	3,263
Trading & Retail	137	4.0x	5.0x	6.0x	546	683	819
<b>Total / Implied (ex-ITC)</b>	<b>3,463</b>	<b>7.8x</b>	<b>8.8x</b>	<b>9.8x</b>	<b>26,935</b>	<b>30,398</b>	<b>33,861</b>
<b>Add: Silver State Solar NPV</b>						<b>583</b>	<b>\$1.28</b>
<b>Add: NPV of Pipeline Projects (Sabal Trail, Mountain Valley Project, etc.)</b>						<b>1,953</b>	<b>\$4.27</b>
<b>Add: NPV of Remaining Solar and Wind Project Pipeline</b>						<b>1,591</b>	<b>\$3.48</b>
<b>Add: NPV of Texas Hedge</b>						<b>296</b>	<b>\$0.65</b>
Less: Total NextEra Debt						(30,396)	
Netting FP&L-associated debt						10,791	
Netting NextEra Transmission-associated debt						411	
Netting Pipeline debt						-	
Netting NEP Debt						1,655	
<b>Net NEE Resources Debt</b>						<b>(17,538)</b>	
<b>NextEra Energy Resources</b>					<b>9,397</b>	<b>17,284</b>	<b>20,747</b>
Shares Outstanding (2017E)					457	457	457
<b>NextEra Energy Resources Value per Share</b>					<b>\$20.56</b>	<b>\$37.82</b>	<b>\$45.39</b>
2017E NI		P/E Multiple					
		Low	Peer	Prem/Discount	Base Multiple	High	
Florida Power & Light	1,818	16x	16.1x	1.0x	17.1x	18x	29,276
NextEra Transmission	34	16x	16.1x	2.0x	18.1x	19x	548
<b>Total Utility</b>	<b>1,852</b>	<b>16.1x</b>			<b>17.1x</b>	<b>18.1x</b>	<b>29,824</b>
Shares Outstanding (2017E)							457
<b>NextEra Utilities Value per Share</b>					<b>\$65.25</b>	<b>\$69.38</b>	<b>\$73.43</b>
Value of the NEP GP per Share (IDRs)					\$2.26	\$3.26	\$4.26
NEP Valuation					\$20	\$25	\$30
Value of NEP LP per NEE Share based on NEP Valuation					\$3.26	\$4.07	\$4.89
<b>NEP Value per Share</b>					<b>\$5.52</b>	<b>\$7.33</b>	<b>\$9.15</b>
<b>Total Equity Value per Share</b>					<b>\$91.00</b>	<b>\$115.00</b>	<b>\$128.00</b>

Source: Company filings, FactSet, UBS estimates

# NRG Energy Inc.

We expect NRG to post 1Q16 adjusted EBITDA of **\$804Mn**, a solid beat versus consensus (\$661Mn). Hedges are rolling off in the Northeast, which means results are likely to be impacted but we see Gulf Coast weather as offsetting some of the negative datapoints from a mild winter, driving positive comps yet again in the retail business. We do not expect a shift in guidance either, albeit acknowledge that the weaker weather could yet place a broader negative bias on FY16 results. We remain towards the midpoint of its existing FY16 range.

**We look for discussion on GenOn restructuring, a plan on the GreenCo biz to come with a more mixed reception as investors wait for action on achieving the debt reduction plan**

**Figure 162: NRG 1Q Results Adj. EBITDA Comparison**

NRG Energy Adjusted EBITDA (\$Mn)	4Q15A	4Q14A	4Q +/-	1Q16E	1Q15A	1Q +/-	UBSe FY16	NRG 2016 Guidance *	2015A
<b>Business</b>									
East	182	227	(45)	229	424	(195)	557		1,057
Gulf Coast	110	56	54	100	116	(16)	307		588
West	9	13	(4)	-	(8)	8	107		102
<b>Business Total</b>	300	294	6	329	529	(200)	971		1,738
<b>NYLD</b>	183	159	24	173	122	51	803		720
Corporate and Other	13	46	(33)	110	17	93	692		230
Wholesale - Total	483	453	30	502	651	(149)	1,774	\$2,350-\$2,475	2,458
Retail Businesses	129	162	(33)	192	172	20	653	\$650-\$725	653
<b>Adjusted EBITDA</b>	625	661	(3)	804	840	(36)	3,118	3,250-\$3,350	3,340
<i>Street Mean EBITDA Est.</i>				661				3,078	

Source: Company reports, ThomsonReuters, UBS estimates

**For more detail on NRG and NYLD, please see our other recent reports:**

[3/9/2016: Explaining the Path Forward](#)

[1/14/2016: NYLD: Darkest Before Dawn](#)

[12/18/2015: NYLD: What Will NRG Do With Its YieldCo?](#)

[12/18/2015: Digging Deep to Find Value](#)

[12/2/2015: Lightning Up at GenOn](#)

## GenOn: Seeking a Resolution, Slow and Steady

GenOn debt restructuring is management's clear top priority with looming maturities, with a goal to resolve any debt issues through the course of this year; we don't expect immediate resolution and see management potentially pursuing tenders at discount to par alongside expected further asset sales.

- Further, management is adamant in targeting consolidated leverage metrics pro-forma for any restructuring no higher than its corporate target of 4.25x Net Debt/EBITDA adjusted for subsidiary distributions. While new effective allocation of G&A expense to the segment is unclear (and a risk if creditors ultimately opt to walk with the assets given the dis-synergies of the \$193 Mn allocated to the segment), favorable resolution to GenOn could drive share appreciation, in our view.
- We emphasize the corporate allocation of \$11/kW-yr is consistent with costs imposed on non-recourse peers such as DYN onto IPH.

## What Happens to Resi Solar? We see a happy ending

One key question remains what happens to NRG Home Solar in the near term, particularly given recent laser focus on cost-cutting. Management first indicated on its September 2015 update call that it was undertaking a strategic review to find a partner for the business or sell it outright. Out of the two options we would expect a JV over a sale, especially if the partner provides the capital behind its expansion plans.

### Why do we think a joint venture is more likely than a sale?

Public valuations for residential solar companies have declined sharply in 2016 (SolarCity, Sunrun, and Vivint Solar are down an average of ~50% YTD) as the macro environment for residential solar has deteriorated with increasing financing costs and competition. A partnership also would allow NRG Energy to retain value from its retail assets: in this scenario NRG Energy would be the 'origination engine' for potential parties interested in residential solar. In the interim, the company is paring back expansion plans (recently shut down North Carolina operations) and should have a resolution in the very near term (recently reaffirmed final resolution of Home Solar and EVgo in 2Q16). We see this becoming a positive source of cash contribution (albeit slight) from a drag today, resolving one of the wider 'overhangs' on the stock today.

## Is CVSR The Next Drop? Private Angle Here too

With management exploring a variety of options around debt paydown and asset monetization, the ~51% stake in CVSR remains one of the key potential sales and NYLD could be tapped for up to half of the remaining MW, with additional project leverage or partnerships remaining most likely alternatives to free up capital and avoid any unnecessary equity raises. We emphasize this remains the next logical project drop into NYLD; with management clearly indicating it would not drop at current valuations given the negative impact to NYLD, it remains effectively subject to a private buyer either investing in the NYLD equity directly or simply holding onto the asset until a date at which CVSR would be 'ready' to drop.

We don't expect NRG to either sell-down any of its contracted projects outside of the YieldCo structure, seeing a premium on maintaining stable assets through the present downturn. Further, we emphasize NRG continues to benefit from the dividends received from NRG Yield – and remains committed to owning the units as a consequence, despite wider investor consternation.

## And What Happens to NYLD Overall?

We think the most likely outcome for NYLD is largely status quo in relation to NRG. Potential roll up would require significant changes/reckoning on the tax equity, land financing, and other fronts, which would make it very difficult. We believe NYLD continues to be a source of value for NRG in the current form and NRG management is likely more focused on corporate deleveraging.

## Capital Allocation: Debt Reduction Underway

The capital allocation debates that Talen discussed on its earnings call and in our management meetings are quite similar to what is currently facing NRG Energy. NRG does not want to ignore the near-term maturities, which explains why the current plan is to reserve \$325Mn of capital to dedicate towards the 2018 upcoming obligation. The objective is to refinance as much of the \$968Mn 2018

**Despite substantial consternation on execution, we see a way forward**

**Management is open to doing a drop via a PIPE to kickstart NYLD growth**

**Objective of capital allocation is to maintain the sustainability of the FCF**

recourse senior debt as possible while keeping the interest rate/terms at least in-line with the 7.625% current NRG Energy senior note. Aside from the refinancing the 2018 debt management remains broadly committed to total debt reduction in 2016 with any other excess cash.

NRG Energy provided more details into its 2016 capital allocation plan where it expects to dedicate \$1.1Bn to debt reductions including a \$325Mn reserve to meet 2018 maturities as it leans into its liquidity to further meet investors' demands for deleveraging. In contrast NRG expects to generate \$850Mn of organic FCF at the midpoint, ~half of which is dedicated towards growth (\$309Mn) and the new reduced dividend (\$75Mn). 2016 EBITDA expectations are unchanged vs. 3Q15 but due to a more aggressive debt reduction plan the estimated corporate debt / EBITDA falls to 4.0x from 4.3x with room for further improvement.

Below we show which obligations NRG paid down via open market transactions during the year which NRG was able to satisfy \$520Mn of principal obligations (**including accrued interest**) for \$467Mn in cash. YTD NRG has repurchased another \$171Mn of NRG Inc. debt.

With respect to share repurchases during 2015 management bought back \$437Mn of shares at an average price of ~\$18.07.

**Figure 163: NRG 2015 Debt Open Market Transactions**

2015 Debt Open Market Transactions				
Senior Note	Maturity	Principal Redeemed	Cash Paid	Cash vs Principal
<b>NRG Energy Inc.</b>				
7.63%	2018	92	97	5.4%
8.25%	2020	5	5	0.0%
6.63%	2023	54	82	51.9%
6.63%	2024	95	47	-50.5%
<b>Total NRG Energy Inc.</b>		<b>246</b>	<b>231</b>	
<b>GenOn Energy, Inc.</b>				
7.88%	2017	33	33	0.0%
9.50%	2018	25	23	-8.0%
9.88%	2020	61	52	-14.8%
<b>Total GenOn Energy, Inc.</b>		<b>119</b>	<b>108</b>	
<b>GenOn Americas Generation LLC</b>				
8.50%	2021	84	73	-13.1%
9.13%	2031	71	55	-22.5%
<b>Total GenOn Americas Generation LLC</b>		<b>155</b>	<b>128</b>	
<b>Total 2015 Debt Open Market Transactions</b>		<b>520</b>	<b>467</b>	<b>-10.2%</b>

Source: Company filings, UBS estimates **Cash vs. principal includes accrued interest**

### Understanding the current liquidity? Collateral postings are quite high

In an effort to distil management's positioning into 2016, we see collateral postings of \$520 Mn as netting against the current \$700 Mn of 'minimum cash' balance to produce a true 'minimum' cash balance in 2016 of ~\$180 Mn. When netted against the actual \$693 Mn of cash on the balance sheet as of 12/31/15, this would suggest \$513 Mn of deployable cash to pay down debt. Given the significant collateral postings to date, we suspect management could wait for cash to roll *back* into the company *prior* to meaningfully deploying more cash flow.

In addition to the \$925Mn available for debt reduction at the NRG level we show estimates for the GenOn level as well. Last year NRG focused on reducing 2021 & 2031 GenOn Americas debt but we expect the focus to move towards the 2017 & 2018 GenOn Energy Inc. obligations as they mature much sooner.

**After cutting the annual dividend to \$0.12/sh from \$0.58/sh, the dividend reduction will create \$145Mn of additional annual capital available for allocation (~17% of 2016E FCF)**

**Figure 164: NRG Energy Change in Debt QoQ**

Material QoQ Debt Changes	3Q15	4Q15	Change
GenOn Energy Senior Notes	1,949	1,830	(119)
GenOn Americas	850	695	(155)
NRG Senior Notes	6,411	6,165	(246)
NRG Renew	3,525	3,343	(182)
Renewable Project Financing	1,886	2,050	164
NRG Yield Revolver	92	306	214
<b>Total NRG Energy Inc.</b>	<b>8,833</b>	<b>8,586</b>	<b>(247)</b>
<b>Total Debt (Inc. Non-Recourse)</b>	<b>19,880</b>	<b>19,496</b>	<b>(384)</b>

Source: Company filings

**Figure 165: NRG Capital Available for Allocation Estimates**

2016 Capital Allocation	NRG Level	GenOn Level
4Q15 Cash & Equivalents	693	665
Less: Minimum Cash Position	(700)	(285)
<b>Plus: YE15 Cash Collateral</b>	<b>520</b>	<b>48</b>
2016 FCF Midpoint	850	(245)
Less: Growth Capex	(309)	(120)
<b>Capital from Sales</b>	<b>125</b>	<b>178</b>
<b>Capital Available for Allocation</b>	<b>1,179</b>	<b>241</b>
Completed Debt Reduction	(159)	-
Debt Amortization/Capital Lease	(20)	(4)
Dividends	(75)	-
<b>Excess Capital for Allocation</b>	<b>925</b>	<b>237</b>
Guided Debt Reduction	(600)	-
Reserved for 2018 Maturity	(325)	-
<b>"2015 Remaining Capital"</b>	<b>513</b>	<b>-</b>

Source: Company filings, UBS estimates

### How can the capital allocation be enhanced?

This could be supplemented by adding up to \$1Bn of secured debt to the assets to help repurchase corporate obligations (again a similar strategy as Talen has articulated). Among the key levers remaining to address the forthcoming maturity in 2017 is untapped secured debt capacity, with upwards of \$700 Mn at the GenOn corp level and a further \$200 Mn at the GenOn Mid-Atlantic Generation (GAG) level.

**Secured debt capacity at GenOn could play a key role**

Another key component of free cash flow is capital expenditures which NRG revised up in 2016 and down in 2017. The most obvious change is that NRG has pulled back on \$205Mn of growth spending from 2015A-2017E at the NRG level.

At GenOn the capital from asset sales could be revised higher as NRG is still \$362Mn to go in its plan to raise \$500Mn.

## Latest MtM outlook

We include our latest look at forward EBITDA estimates. We do not expect management to revise its consolidated EBITDA guidance. Rather given the mild start of the year, we suspect we could revisit more of the same trend we saw in 2015 where losses in wholesale EBITDA are offset with improvements in the retail segment. This would appear to yet again illustrate the value of a combined retail-wholesale operation.

**Figure 166: Updated NRG Energy Adjusted EBITDA Estimates**

EBITDA (\$Mn)	2015A	2016E	2017E	2018E	2019E
<i>NYMEX Assumption</i>	2.51	2.51	2.80	2.88	3.01
Texas	470	187	85	101	142
South Central	118	120	93	117	117
Northeast	1,057	557	465	517	580
West	102	107	110	95	96
NYLD Eligible	171	225	233	311	311
Renew					
NYLD	720	803	801	800	799
<i>Guidance</i>	705	805			
Retail Businesses	739	653	651	683	682
<i>Home Guidance</i>	700-750	650-725			
Corporate, Other, and Unallocated Synergies	(37)	467	537	537	537
<b>NRG Adj. EBITDA (UBSe)</b>	<b>3,340</b>	<b>3,118</b>	<b>2,974</b>	<b>3,159</b>	<b>3,263</b>
<i>Prior EBITDA Est. (UBSe)</i>	3,397	3,118	2,909	3,096	3,180
<i>Consensus EBITDA Est. (4/13/16)</i>	3,235	3,074	2,807	2,957	2,749
<i>Guidance (4Q15)</i>	\$3,250-\$3,350	\$3,000-\$3,200			

Source: Company filings, FactSet, UBS estimates

## Valuation: Raising PT to \$16 from \$14

We include our latest valuation below; our changes below reflect entirely the shifts in commodity MtM rather than any meaningful underlying shifts in assumptions.

We flag among the key assumptions we have made is the fact that GenOn is non-recourse and hence removed from our valuation. This is consistent with our treatment of DYN's IPH subsidiary now of late as well.

**Figure 167: NRG Energy Valuation**

All figures in USD million except per share data								
		2018 EBITDAR		EV/EBITDA Multiple			Enterprise Value	
		Low	Prem/Discount	Base	High	Low	Base	High
<b>NRG Energy (Classic) and GenOn</b>								
Base IPP Multiple =				7.0x				
Texas	101	6.0x	0.0x	7.0x	8.0x	603	704	804
Northeast	295	5.0x	-1.0x	6.0x	7.0x	1,474	1,769	2,064
GenOn Operating Leases	80	5.0x	-1.0x	6.0x	7.0x	400	480	560
South Central	117	6.0x	0.0x	7.0x	8.0x	699	816	932
West (All-Inclusive)	95	4.0x	-2.0x	5.0x	6.0x	378	473	567
Renew (Ex-Ivanpah)	281	9.0x	3.0x	10.0x	11.0x	2,529	2,810	3,091
Retail Businesses (Reliant, GM, E+, D)	683	5.0x	-1.0x	6.0x	7.0x	3,415	4,098	4,781
<b>Edison Mission</b>								
EME - MidWest Generation	194	6.0x	0.0x	7.0x	8.0x	1,164	1,359	1,553
EME - EMMT (Trading)	32	5.0x	-1.0x	6.0x	7.0x	158	189	221
EME - Other (Gas and Other)	68	6.0x	0.0x	7.0x	8.0x	408	476	544
<b>Other, Corporate, and Unallocated</b>								
Synergies	523	6.0x	0.0x	7.0x	8.0x	3,135	3,658	4,180
<b>Total / Implied</b>	<b>2,467</b>	<b>5.8x</b>	<b>-0.2x</b>	<b>6.8x</b>	<b>7.8x</b>	<b>14,364</b>	<b>16,831</b>	<b>19,297</b>
<b>Net Debt and Other: 12/31/15</b>								
NRG Recourse Debt						(8,586)	(8,586)	(8,255)
GenOn Non-Recourse Debt						(2,584)	(2,584)	(1,751)
GenOn and EME PV Operating Leases						(1,154)	(1,154)	(1,154)
Other Conventional Debt (Non-Recourse)						(85)	(85)	(85)
Solar Non-Recourse Debt (Ex. Ivanpah)						(1,731)	(1,731)	(1,731)
Preferred Shares						(331)	(331)	(331)
Cash						1,358	1,358	1,358
Add: NRG Yield Home Solar ~93MWs (YE15) @ \$0.15 CAFD/Watt @ 10% discount rate						140	140	140
<b>NPV of Equity using Hedged EBITDA Methodology</b>						<b>1,391</b>	<b>3,857</b>	<b>7,488</b>
<b>Open Analysis</b>								
Power Hedges	(208)	5.8x		6.8x	7.8x	(1,211)	(1,419)	(1,627)
<b>Total</b>						<b>(1,211)</b>	<b>(1,419)</b>	<b>(1,627)</b>
add NPV of Power Hedges							380	
<b>NPV of Equity using Open EBITDA Methodology</b>						<b>559</b>	<b>2,818</b>	<b>6,241</b>
<b>GenOn Add Back of Neg Equity Value</b>						<b>\$4.43</b>	<b>\$2.88</b>	<b>-</b>
NYLD Class A & C Average Share Price						<b>12.39</b>	<b>13.77</b>	<b>15.14</b>
NYLD Equity Value						1,058	1,176	1,293
\$/share for NRG Energy (85Mn Shares Owned (B & D))						3.53	3.92	4.32
Estimated 2018 Shares Outstanding						300	300	300
<b>Equity value per share (using Avg of Open/Hedged)</b>						<b>\$10.00</b>	<b>\$16.00</b>	<b>\$25.00</b>

Source: Company filings, UBS estimates

## NRG Consolidated FCF (both incl/excl NYLD and GenOn)

Figure 168: NRG FCF Projections

EBITDA to Cash Flow Analysis	2015	2016	2017	2018	2019	2020
<b>NRG:</b>						
Consolidated EBITDA	3,340	3,118	2,974	3,159	3,263	3,213
Interest Expense	(1,158)	(1,400)	(1,413)	(1,366)	(1,220)	(1,141)
Income Tax	-	-	-	-	-	-
Collateral / Working Capital	(685)	(28)	20	159	(14)	7
Other / Deferred Taxes	(15)	429	386	306	367	408
Less: Home Solar	(173)	(100)				
<b>CFO</b>	<b>1,309</b>	<b>2,020</b>	<b>1,967</b>	<b>2,257</b>	<b>2,396</b>	<b>2,488</b>
Maintenance Capex	(413)	(475)	(375)	(375)	(375)	(375)
Environmental Capex	(237)	(250)	(5)	(15)	(20)	(25)
Other (Collateral Adjustment)	477					
Preferred Dividend	(9)	(9)	(9)	(9)	(9)	(9)
<b>FCF Pre-Growth Capex</b>	<b>1,127</b>	<b>1,286</b>	<b>1,578</b>	<b>1,858</b>	<b>1,992</b>	<b>2,079</b>
<i>Guidance</i>	<i>1,100-1,300</i>	<i>1,000-1,200</i>				
<b>Amortization Schedule - Non-NYLD</b>						
Aqua Caliente	28	29	30	31	31	32
CVSR	25	25	26	27	28	29
Viento	22	23	23	24	25	26
NRG Peaker	20	20	20	20	21	21
Cedro Hill	8	9	9	9	9	10
NRG - Other	19	19	20	21	21	22
<b>Debt Amortization</b>	<b>121</b>	<b>124</b>	<b>128</b>	<b>132</b>	<b>135</b>	<b>93</b>
<b>Adjusting for NRG Yield</b>						
NRG Yield EBITDA	(720)	(803)	(801)	(800)	(799)	(799)
Cash Interest Paid	234	234	234	234	234	234
Net NRG Yield Consolidation Adjustment	(486)	(569)	(567)	(566)	(565)	(565)
Dividends from NRG Yield Ownership	73	87	98	110	114	114
<b>Total NYLD Adjustment</b>	<b>(413)</b>	<b>(481)</b>	<b>(469)</b>	<b>(455)</b>	<b>(451)</b>	<b>(451)</b>
<b>Adjusting for GenOn Energy</b>	<b>(255)</b>	<b>(403)</b>	<b>(268)</b>	<b>(177)</b>	<b>(216)</b>	<b>(210)</b>
<b>Total NRG Free Cash Flow</b>	<b>835</b>	<b>929</b>	<b>1,237</b>	<b>1,535</b>	<b>1,676</b>	<b>1,720</b>
		<i>750-950</i>				
Market Cap	4,340	4,340	4,340	4,340	4,340	4,340
Less NYLD Stake	1,203	1,203	1,203	1,203	1,203	1,203
Market Cap (ex-NYLD)	3,137	3,137	3,137	3,137	3,137	3,137
<b>Implied FCF Yield (with NYLD)</b>	<b>19%</b>	<b>21%</b>	<b>29%</b>	<b>35%</b>	<b>39%</b>	<b>40%</b>
<b>Implied FCF Yield (without NYLD)</b>	<b>27%</b>	<b>30%</b>	<b>39%</b>	<b>49%</b>	<b>53%</b>	<b>55%</b>
<b>GenOn EBITDA</b>						
Interest Expense	(202)	(262)	(262)	(282)	(302)	(322)
Maintenance Capex	139	152	94	82	82	82
Environmental Capex	36	62	-	-	-	-
Total Capex	254	334	94	82	82	82
<b>Free Cash Flow (Pre-Leveraged Leas</b>	<b>53</b>	<b>(272)</b>	<b>(141)</b>	<b>(97)</b>	<b>(92)</b>	<b>(129)</b>
Net Leveraged Lease Impact (Deb	(86)	(131)	(127)	(80)	(124)	(81)
<b>Free Cash Flow (Pre-Leveraged Leas</b>	<b>(255)</b>	<b>(403)</b>	<b>(268)</b>	<b>(177)</b>	<b>(216)</b>	<b>(210)</b>
<b>Uses</b>						
Organic Growth Capital	900	500	500	-	-	-
Total Capex	1583	1,225	880	390	395	400
Assumed Share Repurchases	(1)	-	100	100	100	100
Projected Common Dividend	201	74	37	36	35	34
<b>Remaining for Debt Paydown, etc.</b>	<b>(656)</b>	<b>(13)</b>	<b>561</b>	<b>1,332</b>	<b>1,462</b>	<b>1,544</b>

Source: Company reports, UBS estimates

## GenOn Outlook

We include our outlook on GenOn applying a base multiple of 7.0x across the NRG universe, but applying discounted multiples to the PJM assets, as noted below. We continue to expect a substantial restructuring of the GenOn debt will attempt to capture a discount in the par value of the debt in order to enable the company to be consolidated once again.

**Figure 169: Updated GenOn Subsidiary Valuation**

GenOn Energy	2018 EBITDA		EV/EBITDA Multiple			Enterprise Value		
GenOn Mini-Model SOP Valuation		Low	Discount	Base	High	Low	Base	High
Eastern PJM (Excluding - See DCF Below)	30					-	-	-
GEN Mid-Atl NPV @ 10% of FCF through 2020 - Md HAA Retirements Assumed						-	149	223
Western PJM/MISO	130	5.0x	-1.0x	6.0x	7.0x	651	782	912
California	27	4.0x	-2.0x	5.0x	6.0x	106	133	159
Other (New England, NY etc.)	88	5.0x	-1.0x	6.0x	7.0x	441	529	618
Energy Marketing/Gas Contracts	(8)	5.0x	-1.0x	6.0x	7.0x	(40)	(48)	(56)
<b>GenOn EBITDA</b>	<b>267</b>	<b>4.3x</b>		<b>5.8x</b>	<b>6.9x</b>	<b>1,159</b>	<b>1,545</b>	<b>1,856</b>
GenOn Operating Leases	80	6.0x	0.0x	7.0x	8.0x	480	560	640
<b>GenOn EBITDAR</b>	<b>347</b>	<b>4.7x</b>		<b>6.1x</b>	<b>7.2x</b>	<b>1,639</b>	<b>2,105</b>	<b>2,496</b>
<b>Net Debt and Other: 12/31/15</b>								
GenOn Senior Notes						(1,830)	(1,830)	(1,240)
GenOn Americas and Other						(754)	(754)	(511)
PV of GenOn Mid-Atlantic Operating Lease						(672)	(672)	(672)
PV of REMA Operating Lease						(376)	(376)	(376)
Cash (12/31/15)						665	665	665
Net Equity Value to NRG Corp						(1,328)	(862)	362
<b>Net Equity Value to NRG Corp (per Share)</b>						<b>-\$4.43</b>	<b>-\$2.88</b>	<b>\$1.21</b>
<b>Implied Fully Loaded Debt &amp; Leases/EBITDA</b>							<b>8.5x</b>	

Source: Company filings, Platts, UBS estimates

# PG&E Corporation

*Expect a modest beat for the quarter with another **-\$0.10** impact from the delayed GT&S ratecase decision partially offset by higher ratebase earnings.*

We expect a modest EPS beat for 1Q16 at **\$0.76** vs. consensus \$0.74, with the continued delay in the GT&S ratecase expected to result in an approximate **-\$0.10/qtr** hit year over year. With eventual rates retroactive to Jan 2015, the company plans to report the trueup of past authorized revenues (when a final order comes out) as a separate item affecting comparability. These negative impacts are partially offset by \$0.05 of ratebase growth. We also assume another penny from the timing of taxes and other benefits, which is expected to be earnings neutral over the course of the year. While PG&E expects to book another \$0.25 of repairs tax benefits this year, the year-over-year impact is expected to be comparable, although quarterly timing differences may appear. We assume only a small negative impact from miscellaneous items and regulatory matters, although this can be a sizeable number depending on timing issues; 4Q15 was +\$0.09.

**Figure 170: PCG 1Q16E vs. 1Q15A Walk**

1Q16 Earnings Walk	EPS
1Q15 From EPS From Ops	<b>\$0.87</b>
Tax benefit - repairs method and forecast change	\$0.00
2016 timing of taxes and other benefits	\$0.01
2016 Growth in Ratebase Earnings	\$0.05
GT&S timing (seasonality but -0.10 per q)	(\$0.10)
Regulatory & legal matters	(\$0.01)
Nuclear refueling outage	\$0.00
In 1Q15 last traunch of Solar City sale	(\$0.03)
Miscellaneous	\$0.00
Dilution	(\$0.02)
<b>1Q16E Non-GAAP</b>	<b>\$0.76</b>
1Q15 Consensus	<b>\$0.74</b>
2016 Guidance	<b>\$3.65-\$3.85</b>
2016 UBSe	<b>\$3.74</b>
2016 Consensus	<b>\$3.72</b>

Source: UBS estimates, company filings, FactSet

We continue to expect ~\$0.40 of annualized unrecovered GT&S expense to be retroactively recovered once the first phase decision is reached (revenue requirements). A phase 2 decision (safety cost disallowances) is still expected in April/May as well, although the timeframe for the case technically extends to December. **Our estimates are unchanged.**

## Recent actions (see below for details):

- On April 8, Office of Ratepayer Advocates (ORA) filed its recommendation in the 2017 **general ratecase (GRC)** for a **-\$85M** rate reduction in 2017, a **\$274M** increase in 2018 and a **\$283M** increase for 2019. ORA also recommends a third attrition year, with a 3.50% revenue increase in 2020.
- We expect a Proposed Decision for Phase 1 (revenue requirements) of the **Gas Transmission and Storage (GT&S) ratecase** any day now, having already pushed passed an earlier year-end 2015 expectation. Consistent with the earlier April 2015 decision to disallow \$850M of safety spending in the case, **we also expect the utility to write down the last \$160M expense** piece of this total at the time of the final decision, with the remaining capital expense already accounted for on the balance sheet (~\$400M in 2015 and another ~\$300M embedded within the 2016 capital budget).

- In March, PG&E filed a settlement for its **Electric Vehicle charging station pilot**, reducing the cost from \$222M to \$160M with a target of 7,500 Level 2 charging ports and a target of 100 DC Fast Chargers.
- The **San Bruno-related criminal trial** is set to begin April 26. Expect a 6-8 week jury trial. The recent decision by the judge to reject a gross losses calculation reduced the potential penalty from over \$1B to about \$500M. A decision on whether to allow gross gains in the penalty remains deferred, although we note that without this provision, the maximum penalty would shrink to a mere \$6.5M at \$50k/violation/day.
- The **ex-parte reporting Order Instituting Investigation (OII)** has a pre-hearing conference scheduled for April 20.
- A consultant to run the **Safety Culture OII** has been picked. While not an enforcement proceeding, this is more of a lessons learned and improvement process sponsored by the Public Utility Commission (CPUC).
- **Gas distribution recordkeeping** – SED has recommended \$112M penalties and City of Carmel recommended ~\$650M. PCG has already been fined \$11M for violations. The record closed at the end of March with a decision expected afterward.
- PG&E formed the **TransCanyon Alliance** with Berkshire Hathaway and Pinnacle West to explore competitive transmission opportunities solicited by the California Independent System Operator Corporation (CAISO).
- **Distributed Resource Plan (DRP)** – although the company (and other California utilities) are awaiting a response from the CPUC regarding policy and plan modifications, the utility is already including capital spending for DRP-related projects within its 2017 General Ratecase (GRC). Full execution is expected to occur over several ratecase cycles.

## Initiates guidance for 2016 in-line with UBS estimates and consensus

On the 4Q call, guidance for 2016 was initiated in-line with our expectation at \$3.65-\$3.85 vs. UBS estimates \$3.74 and consensus \$3.72. This represents about ~5.6% growth off 2015 normalized for retroactive Gas Transmission and Storage (GT&S) rates and excludes any possible penalties for ex-parte reporting violations in the GT&S case (up to 5 months of revenue requirement). Regarding bonus depreciation, our estimates continue to reflect reduced ratebase and a lack of accelerated capex under the TAMA tracking mechanism.

*Net-net*, our forward estimates are still well below Street expectations.

**Figure 171: Updated PCG Mini-Model – Maximum Ratebase Earnings vs. UBS estimates, 2014A-2019E**

PG&E Mini-model (UBSe)	2014A	2015A	2016	2017	2018	2019
Capex (\$Bn)	4.9	5.5	5.4	5.9	5.9	5.9
Weighted Average Ratebase (\$Bn)	28.2	29.5	32.6	34.2	36.3	38.5
FERC ratebase	4.6	5.1	5.6	6.1	6.6	7.0
CPUC elec ratebase	18.1	18.5	18.6	19.1	19.6	20.1
CPUC gas ratebase	5.5	5.9	8.4	9.1	10.1	11.4
Total Ratebase (including all disallowances)	28.2	29.5	32.6	34.2	36.3	38.5
Compare vs. PCG Guidance	28.2	29.5	32.6	34.3	36.3	38.5
Ratebase CAGR 2017-2019 (Guidance 5%-7%)						6.0%
FERC Allowed ROE	10.90%	10.90%	10.90%	10.90%	10.90%	10.90%
CPUC Allowed ROE	10.40%	10.40%	10.40%	10.40%	10.40%	10.40%
Blended Allowed ROE	10.48%	10.49%	10.49%	10.49%	10.49%	10.49%
Authorized Equity Ratio	52%	52%	52%	52%	52%	52%
MAX ratebase earnings (\$B)	1.5	1.6	1.8	1.9	2.0	2.1
Shares - Year End (Mn)	476	492	505	512	521	521
Shares - Average (Mn)	466	487	498	509	517	521
Equity Issued (\$M)	844	800	700	420	500	-
MAX Utility Ratebase EPS	3.30	3.30	3.57	3.67	3.83	4.03
<b>Growth</b>		<b>0.3%</b>	<b>8.0%</b>	<b>3.0%</b>	<b>4.2%</b>	<b>5.3%</b>
Special Items 2014-2016						
Tax benefit – repairs method and forecast change	0.24	0.20	0.20	-	-	-
Expected GT&S under-recovery (~\$50M)		(0.06)	(0.06)	(0.06)		
Expected offsetting savings and other benefits		0.06	0.06	0.06		
2014 GRC expense recovery (2013 & 1H14)	0.30					
Other	-				-	-
Regulatory matters	0.02					
Miscellaneous	(0.01)					
Sale of Solar City stock	0.06	0.03				
Parent EPS	(\$0.03)	\$1.48	(\$0.03)	(\$0.03)	(\$0.04)	(\$0.04)
MAX PCG EPS	3.88	5.01	3.74	3.64	3.79	3.99
<b>EPS in model</b>	<b>\$3.50</b>	<b>\$3.12</b>	<b>\$3.74</b>	<b>\$3.64</b>	<b>\$3.79</b>	<b>\$3.99</b>
CAGR 2016E-2019E						2.2%
ROE in model	11.11%	9.95%	11.14%	10.49%	10.49%	10.49%
ROE in model before special items 2014-2016	9.29%	4.49%	10.49%	10.49%	10.49%	10.49%
Prior Estimates	\$3.50	\$3.12	\$3.74	\$3.64	\$3.79	\$3.99
<b>Consensus</b>		<b>\$3.12</b>	<b>\$3.72</b>	<b>\$3.68</b>	<b>\$3.87</b>	<b>\$4.10</b>
<b>Guidance</b>		<b>3.65-3.85</b>				

Source: Company filings, FactSet, UBS estimates

## Valuation: Recently raised PT \$2 to \$62 – Maintain Neutral

Our price target remains based on a 2018E P/E and we recently raised our price target \$2 as a reflection of higher peer P/E's in recent months. We remain cautious on the outlook for PCG in light of the state and federal proceedings/investigations but believe that the negative overhangs essentially counterbalance the premium enjoyed by other California utilities for the abundance of capital opportunities and above-average ROEs. An important distinction between PCG and peers is that the PCG's equity dampens the translation from above-average ratebase growth to EPS growth. We struggle to see PCG sustainably trading at any meaningful premium over the horizon, particularly given the challenging regulatory climate.

In contrast we apply 1x-turn premiums to Edison International (SCE) and Sempra (SDG&E and SoCal Gas); in a scenario where PCG did not face AG prosecution/ex-parte risks **and** did not have to issue extra equity, we believe the utility could trade at a premium like peers.

We continue to see a marginally negative risk/reward bias. On a longer-term view, we see the possibility for shares to trade at a discount, or perhaps ~in-line with peers assuming further dilution from subsequent settlements, etc. We believe any negative datapoint or legal finding on the numerous open dockets/investigations could drive investors to value PG&E at a further discount in the near term.

Despite the premium growth ratebase profile, the question remains whether the ongoing concerns of regulatory risk will persist into 2016/17.

**Figure 172: PCG PT rolled forward to 2018E P/E**

PG&E Corp Valuation (UBSe)	Low Case	Base Case/ Formal PT	Upside Case
Ongoing EPS - 2018E	\$3.79	\$3.79	\$3.79
Group P/E	15.5x	16.5x	17.5x
(Discount)/Premium	(5.0%)	0.0%	5.0%
<b>Valuation Scenarios</b>	<b>\$56.00</b>	<b>\$62.00</b>	<b>\$70.00</b>
<b>Upside/(Downside)</b>	<b>6%</b>	<b>17%</b>	<b>32%</b>

Source: Company filings, FactSet, UBS estimates

## Digesting a Heavy Course of Regulatory Risk

*We remain on the sidelines as we progress through a new wave of uncertainty for shares through 1H16. With a Gas Transmission & Storage (GT&S) ratecase proposed decision (PD) potentially imminent, we see no reason to step up in front of this unusually large and high profile case; rather with few investors expecting any unrecoverable items, we perceive a modest downside bias. We remain generally about a ~dime in EPS below Street projections. Further, with the criminal case poised to kick off April 26, shares are likely to remain volatile due to headlines around the cases. More importantly, regulatory risk could persist through 2016 with both a gas safety OII likely to kick off as well as ongoing focus on Carmel investigation; less likely but impactful as circulating threats of fundamental CPUC reform remain. We suspect this story may require more patience than many suspect; all this said, we see the outlook as steadily turning more positive for the company into 2017, assuming it can avoid 2016 pitfalls.*

## Explaining the Discount – can this turn around? It's not imminent

PCG is currently trading at a ~5% discount to regulated peers, consistent with its historical range of a 5%-13% discount. Investors continue to gravitate to the name when the discount has touched 10% as it screens 'cheap' but we still believe the discount is deserved to account for lingering regulatory uncertainties. While many investors appear willing to look past the certainty from the ~\$0.5Bn penalty cap in the San Bruno criminal case, there remains additional risk of potential material disallowances in the GT&S case.

## Potentially good dividend growth

We expect management to host an Analyst Day (hopefully by mid-year) to discuss its outlook once the GT&S and criminal cases are resolved, with dividend growth as a critical element (and now confirmed to occur in 2016). The latest appointment of CFO Jason Wells in place of retiring CFO Kent Harvey begins to build out the bench once more – and as such, we see a sale of any or all operations as less likely *despite* previous comments from the CPUC Chair suggesting a breakup of operations as the company may be too big to be managed effectively. However, an inflection in div growth is among the key positives in '16; the question is *how* quickly would DPS target a return to a 'normal' DPS payout of 60-70% (we assume 10%/yr from '16-'18E).

## EPS growth potential still has upside, but will likely need to wait for the next ratecase

The key question is *when & if* spending opportunities will translate to in-line or above average trends. Management notes that upside to capital spending plans could come with future ratecase filings, but are unlikely to materialize before that. We note our estimates from 2016 through 2019 continue to reflect only 2% EPS growth with a \$0.5B-\$1.5B ratebase reduction now included for bonus depreciation, mostly offset with reduced equity issuances. Management guides to a net EPS impact of about -\$0.02 for every \$0.5B of bonus depreciation. As we note in the table below, this formulation arises from a reduction to equity in proportion to the capital structure (52%) applied to cash from deferred taxes (actual cash not received until 2019 when corporate-level NOLs are expected to be extinguished).

Management guides to a net EPS impact of about -\$0.02 EPS impact for every \$0.5B of bonus depreciation

Figure 173: Net EPS Impact from Bonus Depreciation, 2016E-2019E

Net EPS Impact from Bonus Depreciation, 2016E-2019E					Reduced Equity EPS Impact	Net EPS Impact
Ratebase Guidance (\$B)	Oct-15	Feb-16	Midpt Diff	EPS Impact		
2016	32.6-33.3	32.6	(0.35)	(0.04)	-	(0.04)
2017	34.0-36.0	33.5-35.0	(0.75)	(0.08)	0.05	(0.03)
2018	36.0-38.5	35.0-37.5	(1.00)	(0.10)	0.07	(0.03)
2019	38.0-41.5	37.0-40.0	(1.25)	(0.13)	0.09	(0.04)

Source: Company filings, UBS estimates

Furthermore, the latest ratebase guidance *already* includes all planned capex for PCG's Distribution Resource Plan (DRP) and management has decided not to accelerate any capex under its 2011 TAMA rider that tracks capital additions to ratebase between ratecases (expires at year-end 2016). As a reminder, prior to the extension of bonus depreciation, NOLs had left PCG a non-cash-taxpayer at the holding company level through 2017, although bonus depreciation rules have effectively extended this period through 2019. While this pushes out cash from bonus deferred taxes to the ~2019 timeframe, ratebase is reduced starting in 2017 as the utilities are full cash taxpayers starting in 2017 (alongside the ratebase and revenue reset from the 2017 GRC).

## What's the bottom line? Looking for real EPS growth driving DPS growth

Beyond the near-term focus on regulatory outcomes and criminal proceedings the focus remains on earnings growth. We see a path towards at least in-line ratebase growth translating to even inline EPS growth. When coupled with California's regulatory regime this could be a premium jurisdiction once again. All this said, we suspect below par DPS growth will remain the norm in the interim as a return to 'normalcy' remains the case.

*For further context, please refer to our recent notes:*

[2/19/16 Still a Full Plate for 2016](#)

[1/29/16 Holding Our Horses](#)

[10/29/15 Still Waiting for Resolution](#)

[7/30/15 Pushing it Out](#)

[6/15/15 Moving Up North](#)

[4/30/15 Equitizing San Bruno](#)

[4/2/15 The Golden State Solar Net Metering Debate](#)

[4/1/15 The California Reset](#)

[3/23/15 Less Earnings Growth than Meets the Eye](#)

[2/11/15 Kicking Electric Vehicles Into High Gear](#)

## What's important for PCG?

- **Dividend policy likely awaiting some resolution of many pending dockets.** With a payout ratio of ~50% our 2016 estimate, we expect PCG to wait for resolution of its Gas Transmission and Storage (GT&S) ratecase in 1H16 before articulating any moves to bring up in-line with industry standards. We also note other dockets to watch as well, including the 2017 general ratecase filed in September. Management has already begun to indicate a new GT&S case to follow on the heels of the current case, with resolution now almost a year delayed from original expectations. The utility is also engaged in a FERC transmission case (TO17) with a FERC settlement conference in March and is awaiting approvals for its Distribution Resource Plan filed in July as well a scaled-down Electric Vehicle pilot program.
  - **Dividend growth worthy of special attention into 2016** – what will management target beyond the near-term? We see management as ultimately aspiring towards a utility-average payout ratio with the questions being (1) when will increases come; and (2) whether management will opt for a large one-time increase to rebaseline or to increase the dividend growth rate to be greater than EPS growth to land in the target range over time?
- **Bonus depreciation hits ratebase.** Ratebase forecast for 2019 is \$1.0B-\$1.5B below prior forecasts as a result of bonus depreciation, with no accelerated capex under its 2011 TAMA account to offset the reduction. Furthermore, the current forecast that is expected to be filed in the Feb 22<sup>nd</sup> GRC update already includes elements of the Distribution Resource Plan. While additional upside remains possible, this isn't expected to materialize until new ratecases are filed. The 2017-2019 ratebase CAGR was reduced to 5%-7% (from 6%-8% previously of a 2014 base). This new forecast is expected to be filed as an update to the 2017 GRC on Feb 22 and compares to the previously implied ratebase CAGR embedded in its distribution and generation-only projections in the GRC of ~5%. The upper end of capex guidance includes all requested spending for the GRC, the GT&S case, Transmission Order filing 17, and requests associated with the DRP (see below).
  - The 2017-2019 capex projection virtually unchanged at a range of \$5.4B-\$6.5B for each year (flat through the period) vs. the

Management is committed to raise the dividend payout ratio in 2016

While additional upside remains possible, this isn't expected to materialize until new ratecases are filed

2016 forecast for \$5.6B. The 2016 amount includes \$300M of disallowed San Bruno penalty capital (of \$689M total).

- Management guides to a -\$0.02 EPS impact for every \$500M of bonus depreciation, after considering the effect of reduced equity needs.
- **Expect Phase 1 decision in GT&S case soon.** An ALJ Proposed Decision (PD) for Phase 1 of the Gas Transmission and Storage (GT&S) ratecase was expected by year-end 2015 but nothing has been heard yet. A final decision for Phase 1 is expected after the 30-day comment period following the ALJ's Proposed Decision (PD). In Phase 1, rates and the penalty for ex-parte reporting violations will be decided, with the penalty maximum of 5 months of the incremental revenue requirement. As a reminder, the company asked for a \$532M increase and the Office of Ratepayer Advocates (ORA) recommended \$338Mn. It's possible that the utility may be able to recognize revenue after Phase 1, but the order would need to be analyzed first. With rates retroactive to Jan 1 2015, PCG booked the entire 2015 amount as a separated item affecting comparability, as well as the penalty amount. Phase 2 is still expected in April/May and will focus on categories of spending that will be applied toward the penalty.
  - The Office of Ratepayer Advocates (ORA) filed a motion in December regarding Maximum Allowable Operating Pressure (MAOP) validation and PCG responded on 12/31 arguing that the GT&S case was not an appropriate forum. City of San Bruno also recently filed ex-parte reporting violation allegations within the GT&S case.
- **The 2017 General Ratecase (GRC)** was filed on September 1<sup>st</sup> with a \$457M (\$372M elec and \$85M gas dist) requested revenue increase for 2017 followed by attrition increases of \$489M in 2018 and \$390M in 2019. It includes 2017 revenue requirements of \$2.17B for generation, \$1.83B for gas distribution, and \$4.38B for electric distribution. [A scoping memo was released in early December](#) that laid out the procedural schedule, among other parameters. On April 8, the Office of Ratepayer Advocates (ORA) [filed its recommendation](#) for a -\$85M rate reduction in 2017, a \$274M increase in 2018 and a \$283M increase for 2019. ORA also recommends a third attrition year, with a 3.50% revenue increase in 2020. While management remains confident that their accounting for repairs tax deductions will not be subject to the same level of scrutiny as Southern California Electric (SCE), we note this possibility given material shareholder benefits since the last ratecase as a result of underestimating the impact. PCG believes that SCE's situation is different in that SCE changed methodology after their 2012 ratecase was closed due to a late IRS rule change (PCG says they have applied consistent methodology throughout, but the forecast of benefits was simply underestimated).

**Figure 174: Adopted PG&E 2017 GRC Schedule (A.15-09-001)**

ADOPTED PG&E 2017 GRC PROCEEDING SCHEDULE (A.15-09-001)	
1-Sep-15	Application Filed
29-Sep-15	Initial Public Workshop
29-Oct-15	Prehearing Conference
If necessary	Additional Public Workshops
1-Dec-15	PG&E SmartMeter Cost-Effectiveness Exhibit
22-Jan-16	Supplemental PG&E Testimony (1)
22-Feb-16	Supplemental PG&E Testimony (2)
8-Apr-16	ORA Testimony
29-Apr-16	Intervenor Testimony
May-June, 2016	Settlement Discussions
May, 2016	Public Participation Hearings
27-May-16	Rebuttal Testimony
13-Jun-16	Evidentiary Hearings Begin
1-Jul-16	Evidentiary Hearings End
July 22, 2016	Comparison Exhibit (if necessary)
1-Aug-16	Opening Briefs
15-Aug-16	Reply Briefs
1-Nov-16	ALJ Proposed Decision
1-Dec-16	Final Decision

(1) As determined in this scoping ruling, PG&E shall serve supplemental testimony regarding activities and associated costs to address inaccurate, missing, or inaccessible records for its gas distribution system.

(2) PG&E's supplemental testimony will address the following areas: (i) an updated tax forecast; (ii) updated labor escalation assumptions; and (iii) an update to the methodology allocating shareholder remedy costs between gas transmission and distribution.

Source: California Public Utility Commission

- **ROE case back on deck this Fall: We could see a 2017 cost of capital case after a long hiatus:** Following two extensions of the cost-of-capital (ROE) case for three California investor-owned utilities off the initial 3-year decision, we suspect there could well be a case filed this Fall. We note specifically the cost of capital extension for 2016 suspended the banding mechanism for the ROE, seemingly reflecting consumer concerns that a rising interest rate environment could well push the ROE to the upper end of the band. While we believe the +/- 1% banding structure will remain in place tied to the Moody's Baa Utility index, we think the baseline of this ROE could indeed see some (modest) downward pressure under any formal review. *Although there has been a recent history of affording above-average ROEs to California utilities, the question remains as to whether this will shift under any formal review. Overall, this remains more a downside risk rather than a reality.*
- **Equity in 2016 comparable to 2015.** Management is projecting \$600M-\$800M of equity issuance in 2016 vs. \$800M in 2015. 2017-2019 equity needs are reduced from these levels as a result of San Bruno penalties being fully funded by 2016, rights-of-way spending finishing up in 2017 (~\$50M/yr), and expected cash flows from bonus depreciation in 2019.
- **The company filed its Distribution Resource Plan (DRP) on July 1<sup>st</sup>,** as required by AB 327. The plan is mostly broad strokes, with details to be flushed out in follow-on workshops. Management indicated that capital spending is likely to increase from historic levels in order to accomplish the goals of the plan. The company recently discussed its proposals to spend nearly \$1B from 2016-2019, although we expect actual capital spending plans to be determined formally within future ratecases. This includes:

**We suspect there could well be a case filed this Fall**

**2017-2019 equity needs are reduced**

- Transmission and distribution automation expansion (\$375M)
  - Substation upgrades (\$30M)
  - Distribution line upgrades (\$70M)
  - Electric vehicle charging (\$350M)
  - Advanced monitoring & control (\$140M)
- **Federal criminal charges for San Bruno remain pending**, with the trial set to begin in April 26 2016. The December 8<sup>th</sup> dismissal of \$565M potential "loss-based" alternative fines pertains to the pending criminal indictment against the company and reduces the original estimate of \$1.13B total alternative penalties by half. US District Court Judge Henderson essentially ruled that the government's estimate of victim losses cannot be based solely on \$565M of earlier settlement payments and that presenting evidence to justify these individual losses would be too onerous for the court to consider over the course of a two-month trial. The 2014 indictment charges the company with 27 counts, many of which have pending requests for dismissal by PG&E. This ruling has no effect on the previous \$1.6B penalties levied on the company last year by state regulators.
  - **The Safety Culture Order Instituting Investigation (OII)** will employ a safety consultant who will essentially conduct an audit of utility practices. PCG hopes to be recognized for significant improvements made. For the gas distribution recordkeeping OII, management notes that they have been receiving recognition for recent improvements made to correct problems that are decades old in some cases. Since the company was already fined ~\$17M for the Carmel explosion (which set off this OII), PCG hopes to eventually close the investigation on a more positive prospective outlook, with hearings starting in early 2016.
    - **Related, the ORA at CPUC** is also establishing a new Safety and Enforcement Divisions (SED) to advocate for such outcomes, rather than simply having this within the CPUC organization.
  - **Electric Vehicle program settlement reached.** After PCG filed a 25,000-station proposal this Fall, regulators requested a smaller pilot program at 10% size, or 2,500 stations over two years. However, the company did not think that would be large enough to generate meaningful usage data and has settled with a new proposal for 7,500 stations over three years. Under the settlement, the cost of the Charge Smart and Save program would be reduced by 28 percent from PG&E's \$222M "Enhanced Proposal," to a cost cap of no more than \$160M with a target of 7,500 Level 2 charging ports and a target of 100 DC Fast Chargers. PG&E will seek to achieve these cost-effective deployment goals by offering site appropriate additional technologies, such as dual-port Level 2 charging stations, and seeking cost reductions through the procurement, site selection, and implementation process. Any cost savings on site-specific deployment costs will be used for additional deployment not to exceed the cost cap. While the original proposal was for \$300M capital spend, the reduced sizing has not yet been reflected in capex guidance. However, most of the spending was back end loaded in 2018/19 and beyond and had little effect on most of the visible budget. In any event, management indicates that there is not likely to be any change

in capex forecasting regardless once all other changes are factored in (positive and negative). A Proposed Decision expected by June 2016.

- **SB 350 passed this summer, raising California's renewable portfolio standard to 50% by 2030.** The California Energy Commission (CEC) notes that the recent cost of renewables – even without tax subsidies – is approaching levels competitive with natural gas. [The CEC recommends](#) a "new procurement requirement to increase renewables beyond 33%, including allowing for rooftop solar and better coordination with Western states and Baja California to maximize renewable energy production and better balance production with demand."
- **California sets Net Energy Metering Successor Tariff, but postpones most changes until 2019.** A final decision was issued in January after the December 15<sup>th</sup> Proposed Decision from ALJ Simon of the California Public Utilities Commission (CPUC). The order adopts a successor to the state's Net Energy Metering (NEM) Tariff, as ordered under R. 14-07-002 and required by AB 327. As a reminder, AB 327 is the 2013 state law that among other things, mandated (1) rate tier reform ([ordered July 3<sup>rd</sup> CPUC Decision 15-07-001](#); see our [6/9 report](#) and [7/10 report](#)), (2) the development of Distribution Resource Plans (DRP) by the investor-owned utilities ([filed on July 1<sup>st</sup>, see page 90 of our 7/15 report](#)) and (3) the development of a successor NEM Tariff. Bottom line is that this PD recommends little change from current residential rates as set under the July 3<sup>rd</sup> rate tier reform decision with regard to no significant changes to the current NEM tariff and the use of a minimum bill approach (rather than a higher fixed charge) through 2018. Fixed charges and Time of Use (TOU) rates for residential customers are to be implemented in 2019. More specifically, the PD:
  - Declines to impose any demand charges, grid access charges, installed capacity fees, standby fees, or similar fixed charges on NEM residential customers while the CPUC is working on how, if at all, any such fees should be developed for residential customers.
  - Determines that a better understanding of the impact of customer-sited distributed resources on the electric system will be developed from work currently under way but not yet completed in other Commission proceedings, including but not limited to the distribution resources plan proceeding (R. 14-08-031), the integrated distributed energy resources proceeding (R.14-10-003), and the proposed rulemaking on preliminary issues in setting TOU rates.
  - Identifies the year 2019, which the CPUC has selected as the target for beginning default TOU rates for residential customers, as the appropriate time to review the NEM successor tariff established by this decision.
  - Continues to rely on the minimum bill established in the July rate tier reform order.
  - Maintains that non-residential NEM customers continue to pay all charges for their customer class regardless of their NEM class tariff.
  - Continues current payment of non-bypassable charges and interconnection fees.

- Requires all residential NEM successor tariff customers interconnecting on or after January 1, 2018 to take service on a TOU rate.
- Establishes a Virtual Net Metering tariff for disadvantaged communities.
- Establishes a 20-year grandfathering for the new customers interconnecting under the NEM successor tariff.
- **While most changes have been postponed until 2019**, once approved, this will be among the first instances in which the NEM rate will be revised, with it [currently set at the full retail rate](#) (including grid infrastructure charges) for 20 years for the first 5% market penetration. We see this issue as substantially 'touchier' for the solar industry than rate design and fixed charges, as customer penetration rates are far more sensitive to the NEM rate. Ultimately, the determination of an appropriate NEM policy will have a major effect on the so-called "cost-shift" debate, whereby lower revenue collection from rooftop solar customers under a volumetric rate requires increasingly disproportionate bill increases from non-solar customers to pay for bedrock distribution and transmission infrastructure as well as required ancillary services and other reliability resources.
- **Risk of a more quasi-regulated framework to solar in the future.** Major changes to the policy will substantially complicate the economics of solar as they exist, needing to calculate just how much 'over-production' consumers' push through during peak mid-day hours, which has historically offset evening consumption. Among the ideas floated in California, would be a fixed payback period targeted for customers at a generic rate design – with declines in NEM compensation tied to a market index in declining cost of solar. All around, rooftop solar may be poised to see a more proscriptive (and quasi-regulated) approach around compensation. Determining any 'appropriate' payback period remains a further quandary. *Bottom line NEM is intact for the time being, but should not be assumed to be the status quo for the long term.*
- **TO17 Transmission rate filing was made in July 2015 and the last FERC settlement conference was scheduled for March 18<sup>th</sup>.** The filing requests \$1.5B of revenue, a \$314M increase over the TO16 settled amount, and is intended to recover prospective incremental capital investment from 2017-2019 since then. Embedded ROE in the request is 10.96%, including a 50 bps incentives adder.

# Pinnacle West

We estimate an immaterial miss to consensus of a few pennies in the lightest quarter of the year. We're watching the ongoing UNS Electric ratecase for indications of how PNW will be treated when they file their ratecase on June 1.

The lightest quarter of the year, we expect 1Q16 EPS to come in a few pennies below consensus at **\$0.12/sh**. Weather is seen as a net +\$0.03 benefit as last year was even more unfavorable than 1Q16. LFCR accounts for +2c/sh, and O&M - 0.13c/sh, largely due to a planned maintenance outage at Four-Corners this year.

**Figure 175: PNW 1Q16 vs 1Q15 Walk**

1Q16 Earnings Walk	EPS
<b>Reported 4Q14 Adj. EPS</b>	<b>\$0.14</b>
Normal Weather	\$0.06
<b>Normalized 4Q14 EPS</b>	<b>\$0.20</b>
Weather vs. Norm	(\$0.03)
Weather norm sales growth 0%-1%	\$0.02
Wholesale contracts	\$0.00
LFCR	\$0.02
D&A	\$0.02
Interest Expense	(\$0.01)
O&M	(\$0.13)
Other taxes	\$0.00
Transmission TCA	\$0.02
4 Corners Rate Change	\$0.00
AZ Sun	\$0.02
Other, net	\$0.00
Dilution	(\$0.00)
<b>UBSe 1Q16 Adj. EPS</b>	<b>\$0.12</b>
Consensus	\$0.15
<b>2016 Guidance</b>	<b>\$3.90-\$4.10</b>
UBSe 2016	\$4.05
Consensus 2016	\$4.00

Source: Company Filings, UBSe

**Figure 176: PNW FY16 Guidance**

2016 Guidance	
Electric Gross Margin	\$2.34B-2.39B
Retail cust growth	1.5-2.5%
Weather norm retail elec sales	0-1.0%
O&M *	\$825M-\$845M
Other (D&A, 4 Corn deferrals, TOTI)	\$645M-\$665M
Interest expense (& AFUDC)	\$155M-\$165M
NI fo non-controlling interests	~\$20M
Eff tax rate	34-35%
Average diluted common shares outstanding	~112M
EPS	\$3.90-\$4.10
UBSe EPS	\$4.05
Consensus EPS	\$4.00
* Excludes O&M of \$94 million, and offsetting revenues, associated with renewable energy and energy efficiency programs.	

Source: Company Filings, UBSe

## Proof is in the Pudding

Management has achieved good trailing results, posting a 9.77% ROE after posting 9.6% in 2014. Further, without equity dilution in sight given the impact of bonus depreciation through 2020, mgmt appears poised to subtly raise EPS expectations through the medium-term, likely trending toward the higher end of its implicit 5-7% EPS guidance range (low end is tied to div growth and high end is driven by the 6-7% growth expected in ratebase). While admittedly maintaining the current higher earned ROEs could be a challenge in the near-term, through the rate-case cycle earning its authorized ROE is still a reasonable assumption. Moreover, there remains a wider question around improving structural lag questions in future cases. We suspect the LFCR mechanism, its efficiency tracker, will remain the pivotal and closely watched issue in the upcoming rate case (many observers we have spoken with remain confident the mechanism will hold up to wider challenges).

### What's the holdback? It's tricky with the upcoming election cycle

We think the upcoming election cycle (Aug 30<sup>th</sup>) could prove particularly turbulent for shares. The primary election cycle will be key to watch – with the Republican nominees selected in August; this summer should prove the height of the

**Mgmt is earning its ROE – and without equity – could continue to grow near its ratebase growth trajectory of 6-7%**

regulatory uncertainty cycle. While not explicitly deciding on any solar policies per se, the three seats up for election (or re-election) could prove decisive in upcoming rate cases. We see a decision late this year in the Unisource case – and corresponding decisions in the solar docket – as effectively setting the stage for PNW's Arizona Public Service (APS) case, to be decided by mid-2017.

## UNS Electric Case Could Set Precedent for APS

Three part rate design with mandatory peak use demand charge is now on the table in Unisource's service area (~93K customers), given ACC's staff decision to recommend significant changes to UNS Electric's rate case (the first of several likely to be decided this year). If passed in the current form, rates would be composed of fixed charge, energy charge and demand charge (likely based on summer on-peak afternoon and evening hours). A demand charge is supposed to give consumers a concrete price signal for grid stress, but UNS's service territory may not have the level of grid technology that PNW has deployed for customers, which would make actionable price signals difficult. Nevertheless, in a scenario where \$5.50/kw demand charges are implemented, this could significantly alter bills particularly in solar customer territory. PNW is taking an active role in the UNS rate case in large part due to the precedent-setting aspect of the case although we are unsure of UNS's willingness to take the full three tiered rate design plus proposed increase in solar customer fixed charges, given political push back from solar advocates. We think optional demand charge or separate solar-customer rate design is a more likely compromise, although Staff's recommendations in the case suggest notable willingness within the commission to pursue a full shift to three-tiered design across entire customer base. (Docket No. E-04204A-15-0142)

- The UNS case is ~6 months ahead of APS's:
  - Hearings commenced March 1, 2016 and are now complete
  - Closing briefs April 25th
  - Open Meeting May/June 2016.
  - July 11 ALJ
  - July 21<sup>st</sup> ACC open meeting

## Value of Solar Case Could Set the Tone

The Arizona Value of solar (docket E-00000J-14-0023) general docket has started and could be decided on an accelerated timeline (mid-year) given important read-throughs for PNW's rate case. Hearings are set for April 18-May 6<sup>th</sup>. The outcome of the case will likely set tone for solar-customer compensation: low value would support reducing net metering rate or increasing fixed charges to levels closer to what PNW has previously asked for, but initial evidence is thin and a contrary decision (high value finding) would likely further inflame the solar debate in Arizona. Given recent Staff opinions in other dockets, we see a constructive outcome for PNW as the more likely scenario, although we note the outcome of elections could shift opinions and outcomes materially.

- **History:** Last year, regulators voted 4-1 (Chairman Bitter-Smith dissenting) to move forward with a combined generic docket to consider both cost of service and the value of solar ahead of the next ratecase filing, expected on June 1, 2016. The docket considers topics including methodologies for determining the cost to serve customers with solar and the value of solar. This follows APS' withdrawal of a request to increase the interim \$20/mo fixed charge for

solar customers (up from \$4.90/mo currently) and the company's recommendation to discuss the issues generically in the near-term in order to speed up the ratecase proceeding next year. APS is focused on attempting to generate a Commission decision on these issues by before the June 1<sup>st</sup> APS filing so that they can use the results in the ratecase.

- o **How high will the demand charge be raised?** Under the current solar tariff, customers pay roughly \$5/mo for an average system (assuming 7kW \* \$0.70/kW). With the previous proposal in the state having been closer to \$21/mo, we suspect a compromise is likely to be struck closer to the higher figure (albeit still below). Following the latest federal ITC extension, we perceive less concern over the impact of higher fixed tariffs. The thought process in the initial \$5/mo rate appears to have been tied to an 'incremental' approach, effectively reducing subsidies to the industry gradually.
- o **Workshop on solar should yield 'methodology':** Ultimately, we continue to expect relatively little out of the solar workshop, expecting simply a 'methodology' on how to calculate the cost shift to be determined. This in our mind would establish rough frameworks on the 'value of solar' to the distribution network. We increasingly perceive this to be a complicated question as small penetrations appear to defer the need for grid upgrades, while greater penetrations would appear to drive higher estimates. We look for California to perform its own calculation on the value of solar, seemingly through the latest Distribution Resource Plan (DRPs) filed by utilities to illustrate both the merits and necessary investments to accommodate growing distributed solar penetration. Only with this clarity does the commission appear to feel comfortable in having adequate clarity to meaningfully move from the current compensation scheme.
- o **Where do the commissioners stack up on solar issues?** If there were to be a spectrum, voting records would appear to suggest that Commissioner Bob Burns is likely the least pro-utility, particularly following his petition to push APS for public disclosure of campaign donations to Political Action Committees (PACs). In contrast, we perceive Doug Little as being towards the middle of remaining of commissioners. Chairman Tobin has a limited track record of views on energy off which to judge his position. It's notable that the former Chairwoman, Susan Bittersmith, was targeted by a solar industry group '*Checks and Balances*' despite her modestly more pro-solar attitudes. She ultimately had to resign after the efforts started by the group clouded out her ability to act effectively in her multiple roles.

## No change to UBS estimates or 2016-2018 guidance

On the 4Q call, guidance for 2016 was maintained at \$3.90-\$4.10 vs UBSe \$4.05 and cons \$3.99, with management still confident of achieving at least a 9.5% ROE for the utility. O&M guidance for 2016 is unchanged at \$825M-\$845M. The outlook for 2016-2018 is also unchanged at 2%-3% retail customer growth offset by conservation, energy efficiency, and distributed gen to reach about 0.5%-1.5% net sales growth.

The key remaining sources of uncertainty going forward include the upcoming ratecase filing on June 1 as we watch the UNS Elec ratecase for clues (hearings in

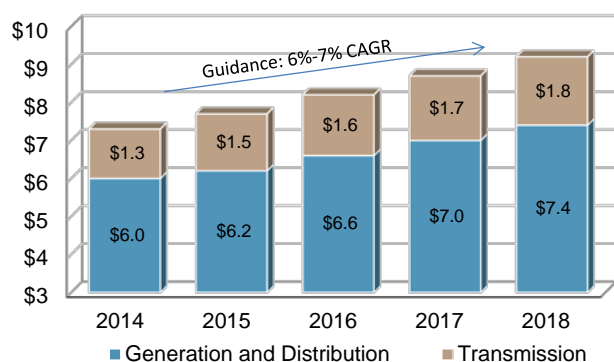
March) amid recent changes at the Arizona Corporation Commission. A key component of the case is now expected to be a request for full revenue decoupling from sales as an improved replacement for the current Lost Fixed Cost Recovery (LFCR) clause (partial-decoupling on sales to offset about 2/3 of the revenues lost as a result of distributed generation).

## Elimination of equity issuances through 2020 keeps earnings intact as '18 ratebase is reduced \$200M

Management had previously highlighted that 2016 guidance assumes extension of bonus depreciation and a corresponding reduction of required secondary equity issuances. The guided ratebase CAGR from 2014-2018 remains 6%-7%, although 2018 is now projected to include \$7.4B of gen and dist ratebase vs \$7.6B previously as a result of bonus depreciation. However, the company now sees no need for equity issuance through the end of the decade as a result of the cash benefits from the effects of bonus deferred taxes. As a result, management expects no net effect on earnings growth from bonus depreciation through the planning horizon (2018). Projected capex was increased \$95M for 2016 (to \$1.2B) and is unchanged in 2017 (\$1.3B), with 2018 initiated at ~\$160M below 2018 levels (\$1.1B). Management expects EPS growth to be between dividend growth of 5% and ratebase growth of 6%-7%. Our estimates result in a 2014-2019E CAGR of 5.5%.

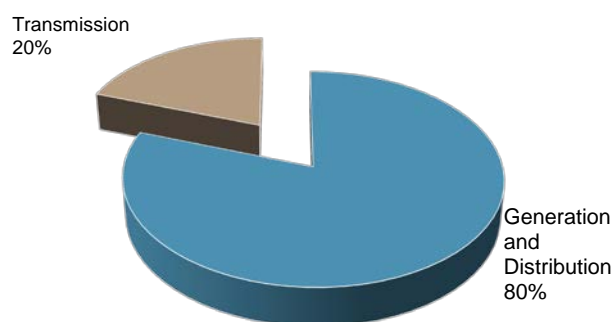
Management expects EPS growth to be between dividend growth of 5% and ratebase growth of 6%-7%. Our estimates result in a 2014-2019 CAGR of 5.5%.

Figure 177: PNW Ratebase Growth, 2014-2018E



Source: UBS estimates, company filings

Figure 178: PNW 2018E Ratebase Breakdown



Source: UBS estimates, Company filings

## Estimates unchanged

Our estimates are largely unchanged, with \$200M lower ratebase in 2018 as a result of bonus depreciation offset with the elimination of equity issuances through the end of the decade. We had *previously* assumed a \$225M equity issuance in 2017.

No equity issuances through the end of the decade.

Figure 179: PNW EPS

	2013A	2014A	2015A	2016E	2017E	2018E	2019E
UBS estimates	\$3.66	\$3.58	\$3.92	\$4.05	\$4.19	\$4.54	\$4.65
CAGR 2014-2019E							5.4%
Guidance				\$3.90-\$4.10		~5% DPS growth	
Previous UBSe				\$4.05	\$4.19	\$4.54	\$4.65
Consensus				\$4.00	\$4.20	\$4.38	\$4.51
ROE Guidance			9.70%	Expect ~9.5% or better in 2016+ vs. 10% Auth			

Source: Company Filings, FactSet and UBSe

## Valuation: Raise PT \$2 to \$75 for higher peer P/E multiple

We're raise our PT by \$2 for a higher utility peer 2018E P/E in recent weeks. We recently downshifted to a peer multiple to reflect our concerns that regulatory risks exist around the composition of any new commission; we emphasize risk will likely increase through the 12-month period beginning June 1<sup>st</sup> around its rate case filing.

Figure 180: PNW Price Target

Pinnacle West Valuation: P/E Derived on 2018EPS					
Valuation		Price Target		Valuation	
2018EPS	\$4.54	2018EPS	\$4.54	2018EPS	\$4.54
P/E Multiple	16.5x	P/E Multiple	16.5x	P/E Multiple	16.5x
Premium/(Disc.)	-10%	Premium	0%	Premium	5%
Value	\$67.00	Value	\$75.00	Value	\$79.00

Source: Company Filings, UBSe

*For additional context, please refer links to relevant recent reports below:*

[1/22/16: Gearing up to Make Their Case](#)

[1/7/16: West Waiting for a Better 2H16](#)

[11/2/15: Shifting towards the Rate Case Cycle](#)

[10/30/15: Hot Summer Meets Expectations](#)

[10/26/15: Catching Some Shade](#)

[9/17/15: Charting Its Own Course](#)

[7/31/15: Holding the Line on Costs](#)

[6/18/15: Sunrise after the Slide](#)

[5/4/15: Maintaining a Low Profile](#)

## What's new at PNW?

- Arizona rate case to be filed June 1:** With four other rate cases expected to be executed in 2016, APS' would be at least the fifth in a series of rate decisions appears likely to be resolved in mid-2017 under the auspices of three new ACC commissioners (only Doug Little and Tom Forese will remain on the ACC). A notice of intent was filed on Jan 29<sup>th</sup>, which included the following parameters:
  - Will propose new rates go into effect July 1, 2017 based on a test year ended Dec 31, 2015 (with some post-test year adjustments)
  - Will propose universal demand rates with an emphasis on residential rate design. Will propose shifting time-of-use rates (TOU) to later in the day to

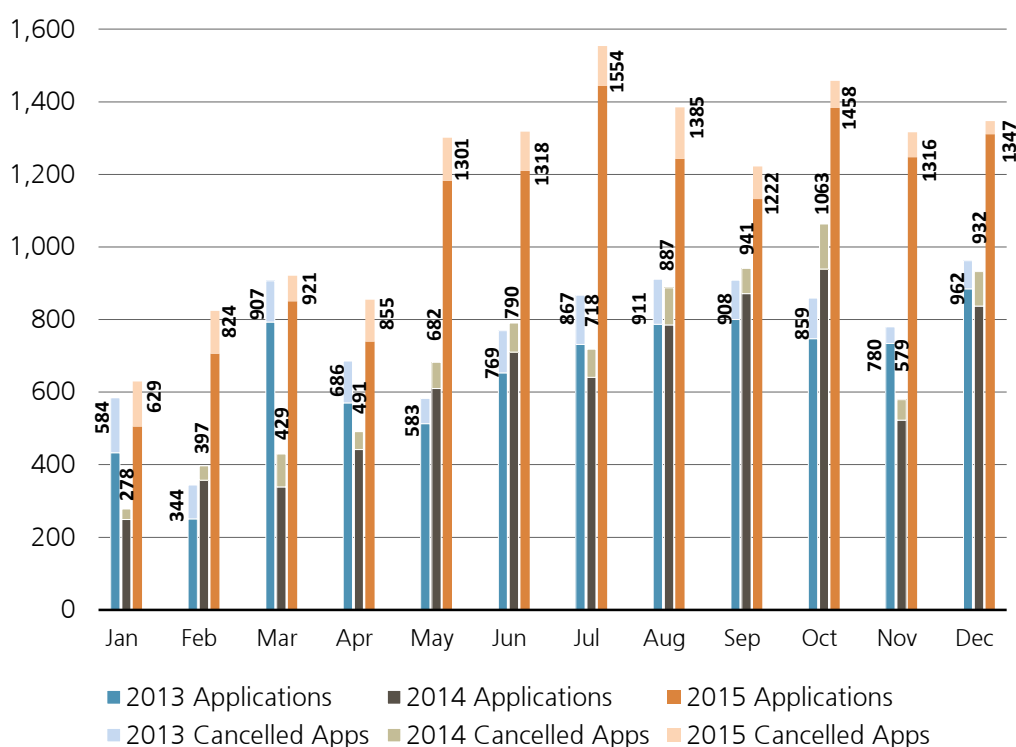
better match peak demand in the 5pm-6pm period experienced in the last year as solar has already shifted the peak-time hours. Just as this is the key risk for solar economics in California, we suspect implementation of TOU rates and shift in compensation could prove a similar dynamic in AZ.

**At the current net metering rate, an APS filing in October estimated the monthly "cost shift" for rooftop solar customers is ~\$67.** According to the utility, residential solar customers only pay for 36% of the cost of transmitting electricity to their homes. More generally, we note that each side is calling out the other's credibility on an issue that could get 'ugly' before a final decision is made.

- o Will request the deferral of \$900M costs related to the SCRs at Four Corners (in service 2018) and the fast-ramping nat gas modernization project at Ocotillo (in service 2019). For the SCR's, the utility will propose a step mechanism for this next ratecase to reflect the deferred SCR costs similar to the treatment of the Four Corners acquisition.
- o Will propose a revenue per customer decoupling mechanism that will be adjusted annually to replace the existing Lost Fixed Cost Recovery (LFCR) mechanism. The decoupling clause will be proposed on a trial basis through the next ratecase as a rate stabilizing mechanism during the transition to a new overall rate structure.
- o Fixed charges and new Time of Use (TOU) rates sought. The current Lost Fixed-Cost Recovery (LFCR) mechanism covers only about 40% of revenues lost to conservation and distributed generation through a surcharge, leaving about \$11M (\$0.09/sh) of the revenue requirement uncollected. In the next ratecase, we expect the LFCR to be eliminated but also for the revenue requirement to be trued up to actual sales in the historic test year. From this new baseline, PNW intends to seek full decoupling (a relative long shot) as well as a shift for Time of Use (TOU) demand rates to later in the day in order to better match peak load with peak net metering payments. The shift would likely result in fewer payments to rooftop solar as peak midday solar generation is earlier in the day than likely proposed TOU rates. The company is also seeking to fix a higher 35%-40% portion of the retail rate structure, which would still be substantially below the 70% of the utility's fixed costs. Even without decoupling, we see the TOU shift and higher fixed charge as potentially stemming the tide of rooftop solar subsidization that has been occurring in Arizona as a result of generous net metering policies. The result should be stronger load growth that would help offset the remaining lost revenue problem that occurs as a result of energy efficiency, conservation, and distributed generation at utilities that collect revenues based on volumetric rates.
- **Preliminary residential solar applications through Dec 2015 are up 73% year over year at 14,130 as monthly totals in July and October reached record highs, eclipsing the previous records in May and June (see table below for a month by month comparison).** AZ rooftop solar applications in 4Q15 were 71% higher year over year at nearly 3,950, with over 37,000 residential photovoltaic (PV) systems installed in APS's territory at yearend '15 (281 MW). While residential solar applications remain strong, we still expect PNW to achieve at least 9.5% ROE through the next rate increase.

- **Solar Ballot Initiative Shows Solar Industry Clout:** Solar Industry Super PAC "Yes on AZ Solar" filed paperwork Friday, April 15 to include a November ballot initiative to require Utilities and the ACC to keep net metering rules unchanged, called the "Arizona Solar Energy Freedom Act". The group is led by former ACC Chairwoman Kris Mayes and will require 225,963 signatures in order to get on the November ballot, which implies several thousand signatures per day. Mayes has indicated "significant" resources will be put into the campaign and they are "in it to win it" with various solar-industry backers (including SCTY). In addition to specifically protecting net metering (through 2022, with grandfathering for any successive rate changes), a successful ballot initiative would attempt to protect solar customers from any other fees that might target solar users specifically as well as any delays in gaining utility approval. We view the latest industry move as a direct response to ongoing/upcoming rate cases with potential significant effects on solar within the state, further evidence that Arizona continues to be a key solar battleground. We continue to watch the Arizona elections closely and believe the successful implementation of the ballot initiative could mark a significant escalation of pro-solar resources and may shift potential outcomes during PNW's rate case later this year.

**Figure 181: Residential PV Applications in APS Territory, 2013-2015**



Source: Company filings, [www.arizonagoessolar.org](http://www.arizonagoessolar.org)

- **The utility's AZ Sun solar program** announced the completion of two 10-MW projects under a utility-scale pilot. Ultimately, we see APS as agnostic to either utility-scale (e.g., its 20MW solution at the Redhawk CCGT in the desert) or its more novel distributed solution. While both options have comparable cost (~\$3,250/kW), we see the bigger issue as being whether the ACC determines there is need for the capacity to fulfill its obligations. The

doubt relates to the current penetration of DG in the state, which is ahead of the targets, as well as projected load growth statistics for the state.

- **APS announced a partnership with the Department of the Navy** to develop a 25-MW microgrid project at Marine Corps Air Station Yuma. The utility also plans to install a 40-MW solar facility this year on behalf of some larger customers. Both projects are reflected in the 2016 capex budget.
- **The APS Solar Partner residential rooftop solar program** is more than halfway toward its goal of 1,500 APS-owned installations (expected to be complete by mid-2016), with the first installation completed in 3Q15. APS will install and own residential rooftop solar systems on 1,500 homes, reaching ~10 MW in cumulative capacity. APS will use this program to evaluate the interaction of DG solar with the grid, in collaboration with the Electric Power Research Institute (EPRI). Contingent on the results, we expect this pilot to be scaled at some point in 2016-2017 after all initial systems are installed and evaluated, although we don't anticipate any real scaling of this effort to compete with 'private' solar developers. We think its pilot program could well be expanded to a full-scale program as the company attempts to push through another avenue for revenue and ratebase growth. While its current program is not competitive against third party leasing providers, we believe any additional effort would likely craft a program that would be competitive.
- **Launched the Solar Innovation Study**, a 75-home demand rate "laboratory" to study the optimal integration of various energy saving and renewable/distributed technologies, such as solar panels, battery storage, smart thermostats, and high efficiency HVAC systems. Customers in the study will be on the utility's existing residential demand rate to study the use of technology to manage peak demand and reduce bills.
- **In May, APS' self-build expansion option at Ocotillo (3 GE 102-MW turbines) was chosen** in the RFP for 300 MW of dispatchable peaking capacity by the summer of 2018 or 2019. At the same time, the cost estimate for the project was reduced to \$500M from a previous estimate of \$600M-\$700M. The in-service date was pushed out a year too to 2019.
- **All-source RFP is out for end-of-decade generation needs.** The utility has issued an all-source request for proposals for new generation in 2020+ (responses are due on June 9<sup>th</sup>, so we don't expect a shortlist announcement until late Summer). This includes combined and simple cycle gas turbines, batteries, and other sources capable of replacing approximately 1,300 MW of power purchase agreement (PPA) contracts rolling off, including PPAs for the Gila River and Arlington facilities through 2019. The company also has two 10-year heat rate option contracts expired at the end of 2015 (500 MW and 150 MW) that have been used for hedging but as generic instruments, these have never matched load very efficiently. Renewable sources are not expected to feature prominently as the bulk of the need is for more flexible capacity capable of providing ancillary services to help stabilize the grid. We expect the company to propose a ratebase option for Gila River and/or Arlington with the argument being that ownership provides a steadier base for stable pricing over the long term (vs 3- 5 year contracts that reset at market). Should the ratebase option be chosen competitively under the RFP, the utility would plan to file an adjustment to the upcoming June ratecase filing in October after the procurement is actually accomplished.

*We continue to see asset acquisitions around the next rate case as a real potential; timing of any deal would likely be in 2H16 given the desire to minimize lag on any investment. This would be incremental to our estimates. Management remains quiet on its prospects heading into what is likely to be a competitive process.*

- **Timing of need for new resources?** With a high-20% reserve margin, mgmt does not appear poised to invest in new plant additions to replace either the Heat Rate Call Options (which weren't that useful anyway) or even immediately as expiring tolls for Gila River and Arlington roll off. As such, it does not appear likely the company will be pursuing additional plant acquisitions in rate base, akin to the effort to acquire the Four Corners coal plant recently.
- **APS is upgrading IT systems to enable** participation in the California ISO energy imbalance market as well as the integration of advanced metering and an improved customer interface.
  - **APS declared its intention to join the western interconnect Energy Imbalance Market** in mid-May. Utility APS announced plans to join the western interconnect Energy Imbalance Market (EIM) in Oct 2016, with systems ready by next summer.
  - **We also flag POR** (Portland General) has also indicated a willingness to join this group.
  - **More efficiency in integrating Western renewables into the grid?** Given the expected sharp intermittency issues introduced by growing renewable penetration into the grid, we see EIM as helping to reduce the 'cost' of backstopping generation to work around greater wind and solar. EIM penetration appears to save greater sums *prospectively*.
  - **It appears the ACC's concerns are more oriented towards the cost of EIM** implementation, rather than underlying jurisdictional concerns of associating with the CAISO (and potential for FERC intervention).
- **Following similar moves in California, we expect an RFP in 2016 for 10 MW of grid-scale storage to be in service by end of 2018.** This follows petitions in the Ocotillo case by RUCO (APS signed a settlement) to evaluate batteries as an alternative. PNW intends to develop a grid-scale storage proposal to develop MWs to effectively meet 'peak' load needs in lieu of additional peak capacity. While still preliminary, we think these investments would indeed be eligible for ratebasing, potentially additive to its current investment plan. This remains relatively long-dated.
- **Expect State Supreme Court to rule on rider authority by mid-2016.** Recall that In Aug 2015, the Arizona Court of Appeals ruled for the Residential Utility Consumer Office (RUCO) in their case against the Arizona Corporation Commission's authority to implement a "system improvement benefit" charge on behalf of Arizona Water, a small water utility. The ruling declared that certain automatic adjustment rider mechanisms (perhaps all of them) are unconstitutional since they violate the requirement for regulators to determine a public service corporation's fair value when setting rates. The potentially larger ramification of the ruling is that it might apply to many other more important riders in the state, especially ones that ratchet only upward, such as the Lost Fixed-Cost Recovery (LFCR) fee currently charged to rooftop solar

owners and the Transmission Service Agreement (TSA). Some adjustors may be safe from challenge since they move in both directions, such as the Power Supply Adjustment (PSA) mechanism.

# Portland General Electric

*We expect a miss vs. consensus for 1Q16 largely as a result of a rate decrease in January and a higher effective tax rate.*

For 1Q, we estimate POR to miss by about a nickel at \$0.60 vs consensus \$0.65. Weather in 1Q16 was very mild, with heating degree days only 85% of normal at 1,584, expected to reduce EPS by -\$0.15. However, 1Q15 was even worse at 79% vs normal or -\$0.20. While guidance for electric sales growth this year had been a modest 1.0%, this excluded what had been believed to be the temporary shutdown of a large paper customer. While this customer is now expected to remain shut permanently, the impact on gross margins is relatively small, so we give +\$0.04 credit for sales growth for the 1Q. The 2015 rate settlement includes a two-step increase, with the first actually a step-down of -\$14.7M in January to be followed by an \$85.1M increase on July 31<sup>st</sup> conditioned on bringing the Carty plant online by then. Higher D&A, O&M, and interest expense is offset by higher revenue from the settlement and is expected to be close to earnings neutral this early in the attrition cycle. As a reminder, guidance for 2016 is for \$515M-\$535M of O&M (vs \$507M in 2015) and for \$315M-\$325M D&A (vs \$305M in 2015). With an effective income tax rate of only 16.7% in 1Q15 as a result of strong wind PTC harvesting, we expect a return to a more normalized 20%-25% (low 20s) for 2016, resulting in a -\$0.05 impact quarter over quarter. We expect a \$0.02 pickup vs last year's variable power costs in excess of baseline under the Power Cost Adjustment Mechanism (PCAM).

**Figure 182: POR EPS Walk 1Q16E vs 1Q15**

POR Earnings Walk	
<b>1Q15A</b>	<b>0.62</b>
Revenues:	
Weather norm from 1Q15A	0.20
Weather 1Q16	(0.15)
Weather norm sales growth @ 1.0% projection for 2016	0.04
Rate decrease for base business (mostly related to NVPC) Jan 1 (\$14.7M)	(0.04)
Rate increase for O&M, D&A, Interest	0.05
Storm cost reserves in 1Q16	-
Decline in supplemental tariffs	(0.02)
PCAM vs Baseline	0.02
O&M	(0.02)
Storm costs in 1Q15	-
G&A	(0.02)
D&A	(0.03)
Interest, including AFUDC debt	0.02
AFUDC Equity (non-taxed)	0.02
Other income	-
Income Taxes (20%-25% for 2016 vs 16.7% in 1Q15)	(0.05)
Other	-
Dilution	(0.05)
<b>1Q16 UBSe</b>	<b>0.60</b>
1Q16 consensus	\$0.65
2016 Guidance	\$2.20-\$2.35
2016 UBSe	\$2.28
2016 consensus	\$2.25

Source: UBS estimates, Company filings, FactSet

## Unchanged 2016E-2020E estimates

Our estimates are unchanged. We remain biased to see dividend growth *rather* than share buybacks in 2016, as some investors have speculated. The question on timing of in-service of Carty remains a critical one. Further, IT related spending is also another item of capex and EPS upside.

**Figure 183: Portland General – Projected EPS Estimates**

	2014A	2015A	2016E	2017E	2018E	2019E	2020E
<b>UBS EPS estimates</b>	<b>\$2.18</b>	<b>\$2.04</b>	<b>\$2.28</b>	<b>\$2.43</b>	<b>\$2.50</b>	<b>\$2.73</b>	<b>\$2.81</b>
UBSe CAGR off 2015 weath norm \$2.20							6.4%
<b>Prior UBS EPS estimates</b>			<b>\$2.28</b>	<b>\$2.43</b>	<b>\$2.50</b>	<b>\$2.73</b>	
Street Consensus EPS (FactSet)			\$2.25	\$2.39	\$2.46	\$2.64	
Management Guidance - EPS			2.20-2.35				
DPS	\$1.12	\$1.18	\$1.26	\$1.35	\$1.44	\$1.54	\$1.64
DPS Growth (quarterly, usually in 2Q)			\$0.020	\$0.0225	\$0.0225	\$0.025	\$0.025
Dividend Payout Ratio (UBSe)	51%	58%	55%	55%	57%	56%	58%
Management Guidance - Payout			50-70%				
DPS growth	2%	5%	7%	7%	7%	7%	7%
Management Guidance - Dividend growth			5-7%				

Source: Company reports, FactSet and UBS estimates; note EPS changes made on 15 January

## 2016 guidance initiated a nickel below expectations due to mild Jan weather

On the 4Q call, POR initiated 2016 guidance of \$2.20-\$2.35 vs UBSe \$2.28 (prior \$2.32) and cons \$2.25 (prior \$2.34). We had expected guidance of \$2.25-\$2.40 but warm January temperatures have already cost the utility -\$0.06 and unfavorable wind another -\$0.02 this year, which is now embedded in 2016 guidance. The midpoint of 2016 guidance is 12% above 2015 results of \$2.04, which was also hit with -\$0.25 of mild weather, partially offset with \$0.09 "temporary" O&M reductions last year. Excluding the effects of weather and last year's O&M reduction, the midpoint of 2016 guidance is about 7% above a normalized 2015 of \$2.20.

Guidance for 2016 also includes O&M of \$515M-\$535M (vs 2015 \$507M) and D&A of \$315M-\$325M (vs 2015 \$305M), levels consistent with those approved in the December rate order. It also assumes non-weather retail electric load growth of 1% and average hydro conditions. The largest driver for 2016 is the two-phase \$70.4M rate increase (excluding reductions of customer credits) primarily for Carty as stipulated last year and approved on Dec 15. As a reminder, a \$15M rate decrease took effect Jan 1 to be followed by an \$84M rate increase for Carty provided that the plant be in-service by July 31. In our walk below, we include the earnings impact of about half a year of \$600M higher ratebase at 50% equity and a 9% earned ROE. We also include half a year of continued AFUDC equity on Carty, although as noted in the table, this eventually declines below 2015 levels as CWIP returns to a more historic level of \$140M-\$200M (absent major plant construction). Overall, we expect earnings this year to be based on a \$4.44B ratebase plus CWIP minus unfavourable weather, which correlates to ~\$2.28 on ~89M shares.

With 2015 ending the year \$3M below baseline costs for the Power Cost Adjustment Mechanism (PCAM), the reset into 2016 will start out about -\$0.03 year-over-year.

**Figure 184: PCAM Quarters (\$M vs baseline)**

	2014	2015
1Q	-3	-2
2Q	-11	+0
3Q	+5	+6
4Q	+2	-7
Total	-7	-3
Neg # means lower power costs vs baseline		
Surcharge/refund +/- 100 bps ROE or ~\$19M		

Source: Company filings

**Figure 185: POR 2016E vs 2015E Walk**

POR Earnings Walk	
2015 UBSe	\$2.04
Revenues:	
Weather norm from 2015	0.25
Weather & wind for 2016	(0.05)
Rate increase for Carty ratebase increase mid-2016	0.24
Rate increase for depreciation and interest	0.10
Rate increase for O&M	0.14
PCAM vs Baseline	(0.03)
O&M, including outage timing	(0.10)
G&A	(0.04)
D&A	(0.12)
Interest, including AFUDC debt	0.02
AFUDC Equity (non-taxed)	(0.05)
Other income	-
Income Taxes (20%-25% for 2015 and assume same for 2016)	-
Dilution	(0.12)
2016E	\$2.28
2016 consensus	\$2.25
2016 Guidance	\$2.20-\$2.35

Source: UBS estimates, Company filings, FactSet

*For additional context, please refer links to relevant recent reports below:*

[3/24/16 Going to Court as Sureties Balk](#)

[3/18/16 Zoning in on Renewables](#)

[2/16/16 Legislative Opportunity Looms](#)

[1/15/16 Putting the Carty before the Commission](#)

## **POR files \$180M+ lawsuit as Carty surety bond providers fight their liability**

On 3/23, POR filed a breach of contract action in the US District Court of Oregon against surety bond providers Liberty Mutual and Zurich, which have pledged a total \$145.6M performance bond for the construction of the 440-MW Carty combined cycle plant. Sureties denied liability in whole in a 3/9 letter that demanded POR first disprove the former contractor Abiensa's arbitration claim of breach of contract. The sureties also claim "various contractual and equitable defenses to payment" as well. POR denies both points and is suing for full payment plus damages for "no less than \$180M". The next steps are an initial discovery conference within 30 days, a joint status report within 120 days, and a proposed pretrial order within 150 days.

## **Higher cost estimate but still targeting July completion**

Construction costs, including AFUDC, have increased to \$635M-\$670M from the previous \$620M-\$655M as a result of the discovery of additional defects, lien removals, and repairs related to work Abiensa had done before being replaced. The utility must place the plant in service by July 31<sup>st</sup> to implement an \$85M rate increase based on \$514M of preapproved costs. For unrecovered costs above that, we expect POR to request an accounting deferral order while they consider filing a

2017 test year ratecase (instead of the current plan for a 2018 filing). Should the plant's in-service date be delayed beyond July 31, the company would continue to record AFUDC and would likely seek an extension for the rate increase while considering a deferral order/ratecase filing for the full cost of the plant. We estimate ~\$160M of unrecovered cost could incur ~\$0.07 annualized drag, with a potential July ratecase filing finishing ~May 2017.

## **Renewables legislation passes –\$1B-\$3B potential opportunity for POR**

Oregon's renewables legislation (SB 1547/HB 4036) was signed into law by Governor Brown after the current abbreviated session that ended on March 4. Among other provisions, the law raises the state's renewable portfolio standard (RPS) to 50% by 2040 with interim targets of 20% by 2020 (unchanged from prior legislation), 27% by 2025, 35% by 2030, and 45% by 2035. It also eliminates coal by wire by 2030 (Colstrip imports by 2035). With passage, we expect two separate ballot initiatives with similar objectives to be permanently quashed.

Oregon currently stands at the 15% renewables level, with each 5% expansion in the RPS equivalent to ~300MW - another ~\$500M Tucannon wind farm. In our modelling and valuation of POR, we assign a 25% probability for future RPS upsizing opportunity, which we estimate could require as much as \$1B-\$3B of new investment through 2040 when including additional gas-fired generation to stabilize the grid (assuming ~50% ratebased).

While we expect a material portion of this development to occur within POR's ratebase, we would also expect independent power producers in the region to highlight the problems with Carty in their effort to argue in favor of PPAs. Notably, the law caps the annual incremental cost of mandated renewables at 4% of the utilities' annual revenue requirement, a move designed to limit rate impact. Furthermore, regulators will have the power to temporarily suspend compliance if necessary to preserve grid reliability.

**Criticism from Commissioners and Staff.** Although we've heard criticism of the new law (and the process that led to it without much Commission input), there appear to be few options for regulators to stand in the way of construction to achieve its technologically-specific goals (focus on wind and solar). Regulators were notably absent from the [Oregon Clean Electricity & Coal Transition Plan](#) proposed in January. The bill is supported by the Citizens' Utility Board of Oregon, Climate Solutions, NW Energy Coalition, Oregon Environmental Council, Oregon League of Conservation Voters, Natural Resources Defense Council, Pacific Power, Portland General Electric, Renewable Northwest and Sierra Club. POR and PacifiCorp have both estimated several \$100M of savings in the legislation vs the original ballot initiatives, with the legislative process providing more flexibility for changes to compliance standards and timelines. Staff is concerned that the law's off-ramps and cost-caps may not be sufficient protection for ratepayers as intermittent renewables take on an increasing proportion of the supply mix. Regulators have also noted to us that without the coordination of surrounding states, Oregon's singular action against "coal by wire" is unlikely to change regional coal dispatch. On the other side of the debate, bill advocates point to the reliability support Oregon will receive from a larger Western Energy Imbalance Market (EIM) taking shape now, along with new technologies that are bringing renewable costs down. POR has also estimated customer bill inflation from the law at no more than 1.5% annually (on average).

**Notably, the law caps the annual incremental cost of mandated renewables at 4% of the utilities' annual revenue requirement, a move designed to limit rate impact.**

**There appear to be few options for regulators to stand in the way of construction.**

## Integrated Resource Plan (IRP) filing coming in 2H16

POR intends to file its next IRP in 2H16, with a final plan in late 2016 followed by an 'acknowledgement' from the Oregon commission in early 2017 indicating POR should move forward with the plan. While not an admission of prudence per se, the document does enable management to pursue corresponding RFPs to meet growth aspirations. RFP winners are based on a "least-cost, least-risk" standard, with purchased power competing on equal terms with potential ratebase projects. The IRP will principally focus on the Boardman coal plant and scenarios for the potential addition of new wind resources. We expect an action plan in mid-2017 with the RFP decision in mid-2018, in time to have new resources in service by the 2020 Boardman retirement. POR will include self-build options.

**The IRP should be the next clue on mgmt's formal load growth expectations – both near and long-term**

On timing, while renewables could probably be delayed longer if necessary (using renewable credits, for example), a new gas unit would certainly be required in 2020. However, with Congress extending the Production Tax Credit (PTC) for wind, we see a renewed impetus for incremental wind in the IRP to take advantage of the tax benefits while aiming for higher RPS standards.

## Early action incentive from non-expiring Renewable Energy Certificates (REC)

From 2016 until the end of 2022, RECs generated from new, long-term renewable projects in those first 5 years have unlimited life, creating an incentive for early action on meeting the RPS. Utilities' existing REC banks also maintain their unlimited REC life.

## Eliminating "coal by wire"

The law also eliminates coal-fired power imports from the state by 2030, although an extension to 2035 is carved out for the Colstrip plant in Montana, of which POR holds a 20%, 296-MW interest in the more modern (and cleaner) Units 3 & 4. While we don't necessarily believe the plant will retire these two units (opting only to shut Units 1&2 for now to address environmental considerations), the law requires POR to find replacement generation. Furthermore, with an offtake arrangement for TransAlta's coal plant in Centralia, WA, this too should add to POR's fuel mix considerations going forward and present new opportunities for possible ratebased generation, albeit through competitive RFPs.

## Clean Power Plan intentions

With no coal in the state, POR had been advocating for a rate-based State Implementation Plan for Oregon's compliance with the EPA's Clean Power Plan (before the Supreme Court stayed the order pending a ruling). We see OR's strong load growth as driving this decision, although another issue of concern for POR is the allocation of emissions allowances between utilities and customers.

## Acquisition of local IPP assets a cost-effective growth route for POR

A further avenue to address growth relates to the potential for management to eventually *acquire* adjacent IPP assets throughout the region in lieu of self-development in future periods. We specifically see CPN's Hermiston plant in OR as better positioned to be eventually acquired and/or dispatched with greater value under the new RPS seeing the clear concerns of the commission around intermittency.

## RPS expansion would change Boardman replacement plan

Under a deal with regulators and the Sierra Club, the coal-fired Boardman plant will be closed by year-end 2020 and needs to be replaced. The plant was among the first economic coal plants committed to be retired nationally. POR increased its ownership stake to 90% at year-end 2014 to a 518 MW share, with the other 10% owned by IDACORP.

Capacity will need to be replaced with additional renewables, a gas-fired plant, or perhaps some combination. Initially it would seem that a new (additional) baseload CCGT unit at the Carty site would be the company's preferred solution, (competitively bid through an RFP). However, with a higher RPS resulting in a significant increase in renewables on the system, we think POR is likely to opt for additional peaking units instead, such as another set of reciprocal gas engines with quick-start capability at Port Westward. The contemplated in-service would seemingly correspond with a 2020-retirement – and drive capex in the 2018 and 2019 period if approved.

The contemplated in-service for a Boardman replacement would seemingly correspond with a 2020-retirement – and drive capex in the 2018 and 2019 period if approved.

## Competing with Northwest Natural for load: fighting CHP

POR appears poised to attempt to block NWN's efforts to file with the commission for the right to develop Combined Heat and Power (CHP) solutions in OR. The company appears keen to limit the progress of these combined electric and steam solutions.

## EIM supported by regulators but does not replace reserve requirement

POR confirmed that its plan to join the California Energy Imbalance Market (EIM) would not allow it to lean on CAISO to meet system reserve requirements. Participants must enter the market "resource sufficient". We continue to expect the EIM program to be adopted across the entire region as governance concerns are addressed. We also note that Oregon regulators have cited the EIM as supportive of grid stability throughout the coming expansion of intermittent renewable resources. We further note they are open to joining an ISO/RTO even (long thought unpalatable) in order to address the intermittency concerns. We note the commission is particularly concerned with the cost of meeting intermittency with greater than 30% RPS, as the current legislation contemplates. We continue to expect a variety of different investments to address the plant.

## More capex coming in Voice and Data Communication upgrades

Figure 186: POR Capex Projections, As of Sep 2015, Nov 2015, and Feb 2016 (\$M)

Capex (ex-Carty)	Sep-15	Nov-15	Feb-16
2015	433	418	413
2016	354	386	414
2017	366	366	342
2018	298	296	305
2019	285	281	281
2020			300

Source: Company filings

As illustrated in the table above, management's latest 5-year capex projection (2016-2020) includes the acceleration of about \$28M of spending from future

years (mostly 2017) into 2016, primarily for customer information and metering projects that were launched in late 2015 (note the \$30M increase in 2016 spending in the November projection).

However, among the key incremental upsides that could drive a near-term revision to capex (2016-2018) is the development of new voice communication networks for field workers. The efforts are designed to modernize POR up to peers, and are simply pending board approval and final project scoping. We suspect this could be a near-term positive once formally reflected worth ~\$70 Mn, largely in '16/'17 spend. Further, we see a subsequent investment in Data Communications as a parallel, larger investment opportunity, scaling investment in ~2017+ with an investment in magnitude that is multiples of the Voice investment.

**We already include new voice communication network capex in our estimates.**

## Still confident on Carty

POR remains confident that the 440-MW Carty plant will be finished before the July 31st deadline (assuming no further issues), which is required under the company's approved rate settlement for an \$85.1M mid-year rate increase to recover no more than \$514M of construction costs plus AFUDC. Discussions with surety bond providers Zurich and Liberty have begun and are expected to continue through the construction period, with management expecting several meetings to arrive at a mutual understanding of the level of coverage to be provided under the bonds' maximum \$145.6M cap. The latest cost estimate, including AFUDC, is \$620-\$655M, or \$106-\$141M above the authorized level.

As a reminder, should the plant's in-service date look delayed beyond July 31, the company would continue to record AFUDC and would face several choices:

1. It could be required to renegotiate its prior rate settlement to seek a new deadline before which the company may place the plant in rates. We wouldn't anticipate much of a problem renegotiating the deadline for a potential delay as long as any excess cost (including extra AFUDC) above the approved \$514M is covered by the surety bonds.
2. Alternatively, POR could seek a special accounting order from regulators to defer depreciation and other costs through to the next general ratecase, although this looks like a tougher route to us.
3. In the event of delays and given no other choices, POR could consider a full rate filing earlier than expected (the current plan is to wait until late-2018).
4. If there are costs above the \$514M uncovered by the surety bonds, we are inclined to believe that POR would stand a fair chance of full recovery for the excess amounts (of capital and on capital, including equity) in the next ratecase given that regulators had already approved the process by which the defaulted contractor Abienza was chosen for the project. This process included an independent third-party scored review of some 10 bids. Without prejudging the outcome of any full review of the facts, we emphasize that a fundamental tenet of the regulatory compact is that any prudent use of the shareholder's balance sheet rightfully deserves full recovery of and on all capital employed, including equity on the books that supports the company's credit rating and cost of debt.

## Ratecase plans are up for debate; decoupling extension request coming anyway

The current plan is to file the next rate case in late-2018. However, as noted above in option (3), management may be considering a 2017-test year filing to take care of Carty should the plant be delayed past the July 31 deadline for implementation of a related rate increase. Prior to the current Carty issues, management had indicated a desire to avoid a filing if possible in light of the latest settlement (note that before the settlement, we had originally expected a 2017 ratecase to be filed in Feb 2016). In any event, revenue decoupling currently goes through yearend 2016, but the company will likely ask for a 3-year extension (or permanence) in a special request next year, which is expected to be non-controversial.

## PT unchanged at \$43; remain Buy rated

We continue to ascribe a 1x premium to a 2018E peer P/E to account for both smid-cap bias, less leverage (no holding company borrowings) as well as improved growth outlook vs. peers. We continue to see POR as among the most attractively priced smid-cap stocks.

**Figure 187: POR Valuation**

Business Segment	Valuation Metric	2018 EPS	Low Case		Base Case			High Case	
			Valuation Multiple	(\$ MM) Value	Base Valuation Multiple	(\$ MM) Value		Valuation Multiple	(\$ MM) Value
Portland General Electric Company	P/E	\$2.50	15.3x	\$38	Peer Multiple	Prem/(Disc) to Peer	Base Multiple	19.3x	\$48
					16.3x	1.0x	17.3x		
							\$43		

Source: Company reports and UBS estimates

# PPL Corporation

Shares continue to underperform in 2016 likely given the weakness of the GBP foreign exchange rate (-4%) and significant uncertainty around the 'Brexit' vote. Despite these macro headwinds we still see PPL as one of the cleaner large cap regulated utilities with minimal headline exposure. The latest F/X and RPI trends for the U.K. are discouraging but this is countered by PPL having among the least exposure to a reduction in ratebase from the extension of bonus depreciation with ~50% of future capex targeting the U.K.

We estimate that PPL will earn 1Q16E adjusted EPS of **\$0.74**, down slightly YoY but in-line with Consensus (\$0.74). Although the UK is expected to be ~flat in 2016 compared with 2015, 1Q16 should be weak as this is the last quarter of revenue step-down in the transition to RIIO-ED1 rates. Management also disclosed updated hedging activity where it monetized current F/X hedges, effectively 'trading' in-the-money 2016 GBP/USD hedges for 2017/2018 at higher strikes. Following the Pennsylvania and Kentucky rate cases in 2015 the key drivers for 2016 are the rate increases and importantly an ability to control costs between rate cases. Weather comparisons are unfavorable but Pennsylvania margin is more resilient to reductions in load (~70% has minimal volume risk).

**KY -8% Degree Days in 1Q16; +15% in 1Q15**

**PA: -10% Degree Days in 1Q16; +18% in 1Q15**

**Despite another year of contracting load growth in KY (-1.4% weather normalized) and unfavorable weather (-2.3% unadjusted decline in sales) in 2015 the subsidiary earned a 10.6% unadjusted ROE - a significant improvement from historical levels.**

**Figure 188: PPL 1Q16E Earnings Walk**

<b>PPL Corp 1Q16 Earnings Walk</b>	<b>EPS</b>
<b>1Q15A Adjusted EPS</b>	<b>0.77</b>
<b>U.K. Regulated (PPL UK)</b>	<b>-\$0.07</b>
Gross Margins: New RIIO-ED1 Rates began April 2015	(0.04)
O&M	0.02
Depreciation	(0.01)
Financing	(0.02)
Income Taxes & Other	(0.02)
<b>Kentucky Regulated (LG&amp;E and KU)</b>	<b>\$0.02</b>
Gross Margins: New Rates Effective July 2015	0.04
O&M	0.00
Financing	(0.01)
Income Taxes & Other	(0.01)
<b>Pennsylvania Regulated (PPL EU)</b>	<b>\$0.03</b>
Gross Margins: New Rates Effective Jan 2016	0.04
O&M	0.00
Depreciation	(0.01)
Income Taxes & Other	(0.01)
<b>Parent &amp; Other</b>	<b>-\$0.01</b>
Corporate Restructuring, Taxes, & Other	(0.00)
Dilution	(0.01)
<b>1Q16E Adjusted EPS</b>	<b>\$0.74</b>
<b>1Q16 Consensus</b>	<b>\$0.74</b>
2016 UBSe EPS	\$2.34
2016 Consensus	\$2.35
2016 Guidance	2.25-2.45

Source: Company Filings, FactSet, and UBS Estimates

For additional context, please refer links to relevant recent reports below:

[2/4/16 Rolling to 2018 at 5-6%](#)

[10/30/15 Adding to the Momentum](#)

[9/17/15 Charting Its Own Course \[Upgrade to Buy\]](#)

[8/17/15 Growing Like Blue Grass](#)

[7/1/15 Peering Across the Pond: Ofgem's RIIO \[Transcript w. Ofgem\]](#)

[6/8/15 Utilities Stand Alone](#)

[5/11/15 Adding a Jewel to the Crown](#)

## What are the pivotal question for PPL?

### How fast can management deliver EPS growth in the UK?

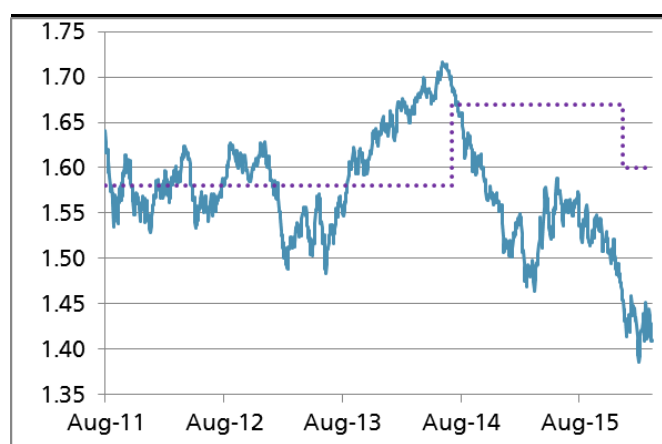
- **PPL hedges aggressively amidst "Brexit" concerns:** In the face of growing speculation and uncertainty about Britain's membership in the European Union, PPL layered in more hedges in 2018 by executing on its re-strike plan. The company outlined in a presentation their expected percentage of foreign currency hedged for 2016, 2017, and 2018 at 95%, 89%, and 41%, respectively. No additional hedging is expected before the June referendum and management still sees latitude to bring the 2018 hedging up to 50% based upon the conservatism in its earnings guidance elaborated on the 4Q15 call. Management does not expect the company's operations in the UK to be affected by the referendum; however, volatility in currency markets may have an adverse effect on earnings. On the 4Q15 call management stated that if there was no improvement in the exchange rate, no restrikes exercised (as mentioned, restrikes have occurred), and no further incremental O&M savings then the EPS CAGR would be in the bottom-half of the 5-6% range. Based on the current exchange rate we forecast a 5.6% EPS CAGR.

On the last call management stated it had built enough conservatism into its 2016/2017 plan to restrike hedges with a \$0.05-\$0.06 expense in FY0/FY1.

No additional hedging activity is expected until after June's vote.

While more capex is coming, this will wait till 4Q16 update cycle

Figure 189: USD/GBP F/X Rate



Source: FactSet

Figure 190: PPL Hedging Profile

FX Hedging			Decrease in Rate		
Year	Hedged %	FX Rate	2015	2016	2017
2015	100%	1.57	(\$0.05)	(\$0.10)	(\$0.15)
2016	95%	1.54	\$0.00	\$0.00	\$0.00
2017	89%	1.58	\$0.00	(\$0.01)	(\$0.03)
2018	41%	1.56	(\$0.01)	(\$0.01)	(\$0.02)
			(\$0.03)	(\$0.06)	(\$0.09)

Source: Company Filings

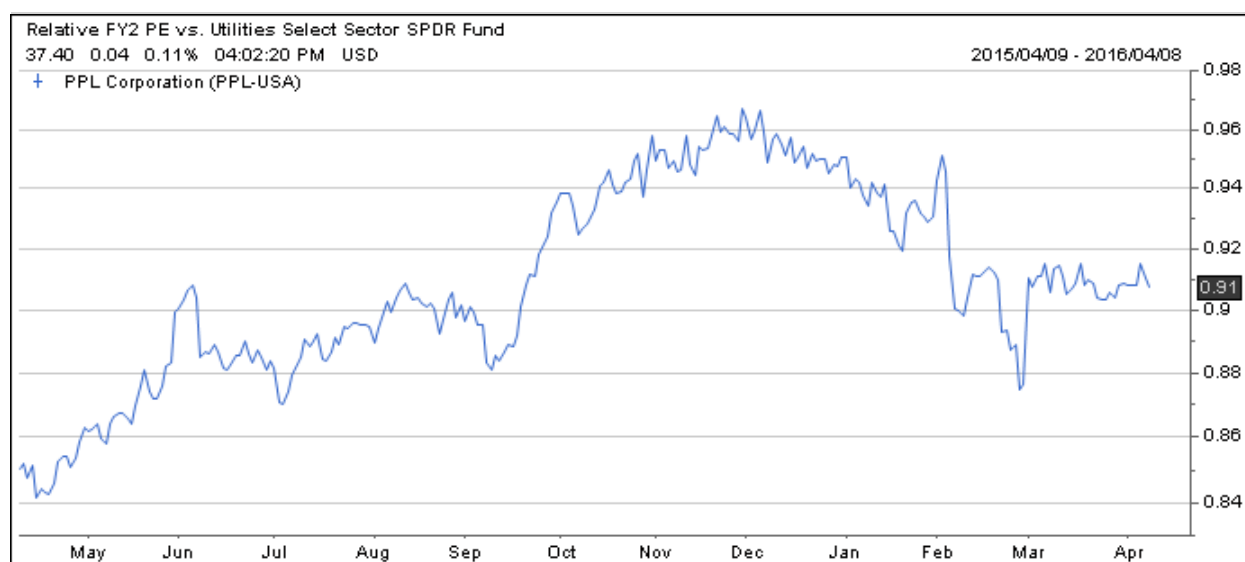
## What is the earnings/capex outlook for the US utilities?

- **More regulated spending potential in both PA and KY but an update is not expected early in 2016:** This could be revealed in the Analyst Day potentially but management highlighted opportunities across the board - gas, solar, and T&D spending acceleration. Perhaps most interestingly was the discussion of gas growth in Kentucky as management has not historically focused there. We would not be surprised to see management ultimately explore gas reserves in ratebase in Kentucky, particularly if it does add more gas capacity at the electric utility. The current plans are not based on the Clean Power Plan but the deferred combined cycle could be added back in the KY plan in 2020-2022, recoverable via the existing environmental rider. Our conversation did not touch upon the Compass transmission project but if management is successful on even portions of the line it would form a solid foundation for growth beyond the current 2014-2018E EPS CAGR.
- **With the shares continuing to underperform, management is increasingly considering an Analyst Day:** PPL rallied in 2H15 and was trading at only a 4% discount in December but has steadily seen its discount expand again and was trading at a 9% discount in early April. While we acknowledge that the foreign currency exchange rate is a headwind we believe shares should be trading at closer to an in-line multiple. We expect management to further emphasize the (1) the cash flow profile of the segment and how it could be valued higher on a dividend yield basis; (2) delta between its utility performance and peers; and (3) growth opportunities in the next rate regime. The Analyst Day would not just focus on the UK but also on how strong/visible the growth profile is domestically. We have historically underestimated the earned ROEs in Kentucky but management has put together a strong track record of performance. Based on its historical pattern we still estimate that rate cases will be filed approximately every other year in KY but we would not be surprised to see management stay-out longer in PA.

Even without Clean Power Plan spending in KY, management believes there could be incremental capex opportunities available in the state outside of environmental. For example: a potential step-up in spending at the gas business, C&I solar, and other T&D spending that it could accelerate after the extension of bonus depreciation.

While timing has not been determined yet, PPL increasingly intends to host an Analyst Day where it hopes to not only help explain the value of the UK business better to US investors but also highlight the earnings power of the US utilities

Figure 191: PPL 2Yr Forward P/E Ratio



Source: FactSet

- **Do not need a partner on Compass but certainly open to it:** The first segment of the Project Compass transmission proposal interconnects with Consolidated Edison's O&R service territory. ED is reviewing the proposal as the transmission operator's technical review but the two companies are not joint venture partners. PPL commented that there could be value in working with the incumbent utilities to help accelerate the local regulatory processes but reaffirmed that it does not need a partner for any technical or financial reasons. ConEd commented in our EEI meeting that it will continue to evaluate non-New York TransCo opportunities on a case-by-case basis. New York is still in the early steps of reviewing the technical aspects of PPL's proposal and the full process is expected to span all of 2016 with more information disclosed publicly around mid-2016 but we expect some clues on the 1Q16 call as well.

PPL stated it was open to a JV partner on the ~\$500 Mn project (Phase I only) but it did not necessarily see any reason to bring in an outside player unless there was a strategic rationale. We see ED as the logical partner.

## EPS Estimates intact

Our latest EPS estimates are below which are largely unchanged after incorporating the March hedging update detailed previously and the latest foreign exchange rates. We continue to forecast a 5.6% 2014A-2018E adjusted EPS CAGR; in contrast our EPS CAGR was ~6% in late 2015 when the GBP was trading in the ~\$1.50s compared with the low ~\$1.40s in early April.

Figure 192: Updated PPL Earnings Estimates

PPL Standalone EPS (UBSe)	2014A	2015E	2016E	2017E	2018E	14A-'17E CAGR	14A-'18E CAGR
UK Utilities	1.37	1.44	1.43	1.42	1.41	1.3%	0.7%
PA Electric Utility	0.40	0.37	0.46	0.52	0.60	9.3%	10.5%
Kentucky Utilities	0.47	0.51	0.56	0.59	0.62	8.0%	7.1%
Retained Supply Corp. & Other	(0.21)	(0.12)	(0.10)	(0.12)	(0.10)		
<b>Total</b>	<b>2.03</b>	<b>2.21</b>	<b>2.34</b>	<b>2.42</b>	<b>2.53</b>	<b>6.0%</b>	<b>5.6%</b>
Prior UBSe	2.03	2.21	2.34	2.43	2.52		
Consensus (4/8/16)	2.03	2.21	2.35	2.44	2.51	6.3%	5.4%
Guidance		2.15-2.25	2.25-2.45	2.42	2.52		
FFO (CFO pre-W/C) / Total Debt		14%	16%	16%	16%		

Source: Company Filings, FactSet, and UBS Estimates

## How were PPL's prospects impacted by bonus depreciation?

Below we recap the most significant changes to guidance from the 4Q15 update when management rolled-forward its adjusted EPS CAGR to a 5-6% range (2014Adj-2018E) vs 6% (2014Adj-2017E). Although there are areas of weakness (declining sales volume and ratebase primarily), our revised estimates are still in line with guidance expectations and we see a clear path to hitting the top-end of the new 2014Adj-2018E guidance range if the GBP exchange rate recovers. With approximately half of its prospective capital spending focused on its U.K. subsidiaries, PPL has among the least exposure to a reduction in ratebase estimates from the multi-year extension of bonus depreciation as shown with the updated disclosures. In Figure 2 we show that the UK CAGR decreased only 30bp. Bonus depreciation is not covered in the rider mechanism in Kentucky. PPL formally removed an additional ~\$650Mn CCGT from its KY capex forecasts but management has discussed this possibility for over a year following the notification of 320MW planned municipal peak contract cancellations in August 2014. [Further details on that plant are available here.](#)

U.K. mix shields PPL from full effect of bonus depreciation.

Mgmt commented that it could reaccelerate some spending to offset ratebase declines but is still calibrating its plan.

\$270Mn of PA distribution spending was avoided due to better than expected system reliability.

Figure 193: Comparison of Overall Guidance Details

Comparison of Prior (Left) and New (Right) EPS Guidance			
2014Adj-2017E: 6% EPS CAGR		2014Adj-2018E: 5-6% EPS CAGR	
US Utilities: 12-14% Growth		US Utilities: 11-13% Growth	
<b>PA: 11.4% Ratebase Growth</b>		<b>PA: 8.4% Ratebase Growth</b>	
\$2Bn Transmission Capex		\$2.7Bn Transmission Capex	
Undisclosed Load Growth		+10bp Load Growth	
2Yr Bonus Depreciation		5Yr Bonus Depreciation	
<b>KY: 5.6% Ratebase Growth</b>		<b>KY: 3.2% Ratebase Growth</b>	
\$1.2Bn Environmental Capex		\$1.7Bn Environmental Capex	
Minimal Load Growth		+50bp Load Growth	
2Yr Bonus Depreciation		5Yr Bonus Depreciation	
<b>Corporate:</b>		<b>Corporate:</b>	
<\$200Mn Annual Equity		\$100Mn Annual Equity	
UK Utilities: 1-2% Growth		UK Utilities: 1-3% Growth	
15-18% Average ROE		14-17% Average ROE	
5.8% RAV Growth through '17		5.7% RAV Growth through '18	
F/X: 2016 (\$1.56) / 2017 (\$1.60)		F/X: 2017 (\$1.58) / 2018 (\$1.60)	

Source: Company Filings

Figure 194: Comparison of Ratebase Growth

Comparison of Ratebase Growth			
Prior	2014A	2019E	CAGR %
PA	4.9	8.4	11.4%
KY	8.3	10.9	5.6%
UK	9.7	12.8	5.7%
Sum	22.9	32.1	7.0%
New	2015E	2020E	CAGR %
PA	5.2	7.8	8.4%
KY	8.8	10.3	3.2%
UK	10.3	13.4	5.4%
Sum	24.3	31.5	5.3%

Source: Company Filings

## Valuation: Maintain \$38 Price Target

Our valuation is based on a 2018E sum-of-the-parts. We continue to apply a discount to the UK business given its below-average cash flows, flat EPS profile, foreign currency risks, and leverage. We have increased the discount to 1.5x from 1.0x due to the increase in the US regulated utilities peer multiple to 16.5x from 15.3x at the time of our last update. Every 1x-turn change in the UK business is worth ~\$1.50/sh in our valuation.

While investors continue to be concerned about the currency we see those fears as overstated. PPL is one of the few large cap regulated utilities with a 'clean' regulatory calendar ahead and we look for the relative P/E discount to close over time.

Figure 195: PPL Sum-of-the-Parts Valuation

PPL Sum-of-the-Parts (UBSe)	2018E	P/E Multiples					Enterprise Value		
		P/E	Prem/ Disc.				Low	Base	High
<b>International (UK) Utilities</b>	<b>\$1.41</b>	<b>12.8x</b>	<b>15.5x</b>	<b>-1.0x</b>	<b>14.5x</b>	<b>16.5x</b>	<b>\$12,267</b>	<b>\$13,951</b>	<b>\$15,875</b>
<b>Domestic Regulated Utilities</b>									
PPL Electric Utilities (PA T&D)	\$0.60	15.0x	15.5x	1.0x	16.5x	17.5x	\$6,109	\$6,719	\$7,127
PPL Kentucky (KU/LG&E)	\$0.62	14.0x	15.5x	0.0x	15.5x	16.5x	\$5,914	\$6,547	\$6,970
<b>Parent Interest Expense Drag</b>	<b>-\$0.10</b>	<b>14.0x</b>	<b>15.5x</b>	<b>0.0x</b>	<b>15.5x</b>	<b>16.5x</b>	<b>(\$965)</b>	<b>(\$1,068)</b>	<b>(\$1,137)</b>
PPL Equity Value							\$23,325	\$26,150	\$28,835
Shares Outstanding (2018E Mn)							682	682	682
<b>Total PPL Equity Value Per Share</b>							<b>\$34.00</b>	<b>\$38.00</b>	<b>\$42.00</b>
<b>Implied P/E</b>							<b>13.5x</b>	<b>15.2x</b>	<b>16.7x</b>
<b>Premium/(Discount) to Group</b>							<b>-2.0x</b>	<b>-0.3x</b>	<b>1.2x</b>

Source: Company Filings, FactSet, and UBS Estimates

# Public Service Enterprise Group

PEG has consistently outperformed peers in early 2016 trading but is still relatively flat after sharply underperforming from October-December 2015. We viewed the Analyst Day as another constructive update as this conservative management team continues to outperform expectations. We continue to believe that the merchant subsidiary is undervalued and the latest rally in IPPs appears to have benefited PEG as well.

We estimate PEG will report 1Q16 EPS of **\$0.87**, shy of Consensus (\$0.91) and representing a steep decline versus 1Q15 (\$1.04). At the regulated utilities the growth T&D ratebase is expected to be partially offset by higher D&A with the change in the pension methodology countering organic O&M inflation. Although we expect a largely flat quarter at the utility with O&M control, we expect growth to pick-up for the balance of the year given the +\$0.22/sh midpoint guidance for FY16. At Power the combined impact of lower capacity/energy and operational expense inflation pushes our estimates materially lower YoY. Enterprise/Energy (formerly Energy Holdings) should see a modest degree of improvement as the contract steps-up in 2016.

**Lower capacity revenue and an unfavorable power environment drive a negative 1Q outcome. Approximately half of the reduced FY16 Power earnings are expected to hit 1Q given the YoY capacity market trends.**

**Figure 196: PEG 1Q16E Earnings Walk**

<b>PSEG 1Q16 Earnings Walk</b>		
<b>1Q15A Adjusted EPS</b>	<b>\$1.04</b>	<b>Notes</b>
<b>PSE&amp;G YoY</b>	<b>(0.00)</b>	
Transmission Investments	0.03	Increase in Ratebase of ~\$1 Bn (tracking at +\$0.03-\$0.04 EPS YoY)
Distribution Investments	0.01	Increase in Ratebase of ~\$500Mn
Weather/Volume Impact	(0.03)	Unfavorable degree day comparison but weather norm. clause (WNC)
Renewables, CIP, & Other	0.01	
O&M Growth	0.00	1-2% growth in O&M; offset by pension accounting change
D&A	(0.02)	Increase mostly offset by the transmission growth; \$27Mn bonus D @ T
Taxes and Other	0.00	
<b>Power YoY</b>	<b>(0.18)</b>	
Capacity Payments	(0.04)	~1.8GW less for 2015/2016 vs 2014/2015
Hedges & Output Volume	(0.07)	56TWh @ \$52 in 2015   56TWh @ \$51 in 2016; negative commod. MtM
Weather/Volume Impact	(0.05)	Gas send-out adjustment primarily
O&M Growth	(0.01)	1-2% growth in O&M; pension. Might offset given the weather
Outages	-	No material outage delta between periods
D&A	(0.01)	Organic increase in depreciation from spending; bonus D impact
Interest Expense	-	Slight benefit from Power Refinancing
LIPA Fuel Mgmt Contract	0.00	Services arrangement ~+\$0.01 YoY
<b>Enterprise/Other YoY</b>	<b>0.01</b>	<b>Increase in overall management \$0.03-\$0.04</b>
<b>1Q16E Adjusted EPS</b>	<b>\$0.87</b>	
<b>1Q16 Consensus</b>	<b>\$0.91</b>	
<b>2016 UBSe EPS</b>	<b>\$2.89</b>	
<b>2016 Consensus</b>	<b>\$2.90</b>	
<b>2016 Guidance</b>	<b>\$2.80-\$3.00</b>	

Source: Company Filings, FactSet, and UBS Estimates

For additional context, please refer links to relevant recent reports below:

[3/16/16 Powering Up the Balance Sheet](#)  
[2/22/16 Tracking New Jersey](#)  
[12/22/15 Garden State Greenery](#)  
[11/3/15 Furthering the Gas Prospects](#)  
[8/6/15 Will Power Hold the "Keys" to the Future?](#)  
[6/18/15 The Right Keys to Unlocking Value](#)  
[5/6/2015 Voted Off Artificial Island](#)  
[3/13/15 Doubling Down on New Jersey](#)  
[2/18/15 Deconstructing the Risks in NJ's BGS Auction](#)

## What are the pivotal questions for PEG?

### What is the next big initiative for the regulated utilities?

- Can PSE&G deliver on its utility capital expenditure targets?** Yes. Based upon PEG's 5+ year track record of consistently outpacing its base capital spending plan we have embedded 75% of the opportunity into our utility earnings estimates. The increase in the 2016-2018E PSE&G utility capex to ~\$8.3Bn from \$7.5Bn at EEI was previewed with 4Q15 earnings ([details here](#)) but the more important new disclosure with the March Analyst Day is the opportunity above the base plan that management is working to deliver. Management highlights ~\$750Mn annual of additional potential capital spending in 2019+ ('only' \$400Mn upside to 2017) which would keep utility capital spending largely constant at \$2.5Bn per year in 2018-2020E versus ~\$3Bn per year in 2016/2017. In contrast at the 2015 Analyst Day PSE&G expected \$2Bn capex with upside in 2018/2019. In the Figure below we show an analysis of PEG's 2011-2016 Analyst Day disclosures showing that management has consistently out delivered on its utility capex commitments. For example, based upon its latest disclosures PEG expects \$3.05Bn of capex in 2017E versus \$2.15Bn in 2014; this new base case is even higher than the old \$2.85Bn upside case. With a conservative management team we believe that investors will largely embed the majority of the opportunity capex into their estimates as well. We expect utility to grow ratebase at 8-10% from 2015A-2020E so we believe that the subsidiary deserves a premium valuation.

GSMP was PEG's fourth infrastructure program. PEG discussed the possibility of pursuing more trackers and potentially having a longer rate case cycle.

Figure 197: PSE&G Utility Capex Disclosed at Each Analyst Day

Capex Guidance (\$Mn)	2013	2014	2015	2016	2017	2018	2019	2020
2011 Analyst Day	1,600							
2012 Analyst Day	1,800	1,675						
2013 Analyst Day Base	2,050	1,700	1,200	975	1,000			
2013 Analyst Day Upside	2,150	2,300	2,050	2,100	2,050			
2014 Analyst Day Base		2,250	2,300	1,850	2,150	1,800		
2014 Analyst Day Upside		2,500	2,750	2,400	2,850	2,400		
2015 Analyst Day Base			2,700	2,550	2,400	1,750	1,700	
2015 Analyst Day Upside			2,700	2,725	2,625	2,075	2,000	
2016 Analyst Day Base				3,200	3,050	2,250	1,900	1,850
2016 Analyst Day Upside				3,200	3,100	2,650	2,650	2,625
<b>Actual Capex</b>	<b>2,207</b>	<b>2,170</b>	<b>2,692</b>					

Source: Company Filings and UBS Estimates

### What is driving this potential growth opportunity?

- **Distribution:** \$300Mn annual spending on modernization and life cycle replacement programs which would likely be focused closer to the customer rather than the substation oriented storm hardening from Energy Strong.
- **Gas Distribution:** Another \$300Mn upside opportunity based on extending the recently approved Gas System Modernization Program
- **Solar:** \$200-\$300Mn over a multi-year period for small scale (<10MW) projects with recovery via clauses.
- **Transmission:** Management does not quantify the amount of incremental spending above the base plan and highlights FERC 1000 competitive transmission opportunities. Based upon management's consistent ten-year history/projection of \$1.4Bn of annual transmission capex, we think there could be incremental growth even without competitive projects.
- **Still on track for 2017 case; step-up expected on recovery:** PSEG remains on track to file its next case by November 2017 to recover portions of recent stimulus programs for Energy Strong (\$220Mn), the \$250M Gas System Modernization Program (GSMP), and long-deferred costs associated with past storms including Irene and Sandy, among others (feeding into consolidated cash flow metrics).
- **Sending out "invitations" for distribution upgrades; AMI could be next focus:** NJ regulators have been generally supportive of infrastructure investments, especially concerning gas distribution upgrades, pipeline construction, and resiliency spending. The Energy Master Plan (EMP) is intended to be an "invitation" for the state's utilities to provide further plans for the initial build out of a backbone for Automated Metering Infrastructure (AMI), the meters themselves, continued Energy Efficiency (EE) programs with a growing focus on efficacy, and other grid enhancement in support of future distributed resources, such as "self-healing circuits". Funding for these upgrades could be accomplished through riders, traditional rate cases, or a combination of both. For EE, regulators are also considering the cost/benefits of private-sector initiatives vs a more regulated utility approach through BPU-funded programs.

Outlook for utilities and renewables remains intact in NJ based on our meetings with the NJ BPU. We remain comfortable with the existing recently authorized ROE of 9.75% in recent stimulus investment deals (with neither upside or downside to this level).

### What will management do with the excess cash flow?

- **Robust cash flow creates questions around deployment:** PEG views share repurchases as a much better use of capital than pursuing M&A at the significant premiums which we have seen lately. Share repurchases are certainly an option that the Board could evaluate and management believes there is latitude to increase the dividend as well. While Power's earnings has some cyclicity, the company would be comfortable using its balance sheet for brief period of times to compensate for any perceived short-term volatility to facilitate smooth dividend increases. This is not to say that PEG would risk the balance sheet quality but a signal that it is comfortable with the longer term trajectory of its merchant assets' cash flow profiles. With bonus depreciation only improving the total long-term cash flow generation profile, we see many options as being on the table. As we mentioned before, a more material expansion into renewables could be a partial answer as it has been for peers Duke, Con Edison, and others.

PEG views share repurchases as a better use of capital than M&A at a significant premium.

- **Illustrating the potential to lever up Power and grow Utility earnings to support the dividend:** Power's balance sheet is strong at only 27% debt and 2x-3x debt/EBITDA vs IPP peers at an average 4x-5x debt/EBITDA. In the tables below, we highlight management's own guidance that Power could add another ~\$1.2B of debt at Power and still maintain FFO/debt metrics above 30%. We further show that up to \$3.6B could be added while still keeping FFO/debt above 20% (more in line with IPP peers).

If \$1.2B were reinvested at the utility at a 10% ROE, we estimate the additional regulated earnings growth would reduce the utility's "standalone" payout ratio from ~90% to ~80% from 2016E-2018E while still maintaining our estimated 5% growth rate. We estimate a \$3.6B reinvestment would bring the 2018E standalone payout down further to 66%. We also note that at the current high P/E ratio, share buybacks are not as accretive as reinvesting in utility ratebase at 10% ROEs.

While several hurdles stand in the way of a spin of the merchant business (either full divestiture or spin to shareholders), we note that the utility could support our estimated annualized 5% dividend growth profile on a standalone basis if Power's strong balance sheet were deployed to ramp up regulated investment

### What is the outlook for the unregulated construction projects?

- **FERC released schedule for PennEast pipeline which pushes expected in-service date target back to 2H18 from late 2017 previously:** Based on the March 29<sup>th</sup> FERC notice of schedule for environmental review the Environmental Impact Statement (EIS) is expected on December 16, 2016 with the federal authorization deadline on March 16, 2017. In response to the schedule from FERC, the PennEast board preliminarily pushed the target operational completion date back one year to 2H18. The previous construction timeline was approximately seven months with PennEast looking for FERC approval in 2H16. PEG commented that they were not surprised by the schedule and they remain committed to the ~\$1Bn project in which they have a 12% interest. Docket No. CP15-558-000
- **PEG partnering with Vectren in MISO competitive bid:** Vectren (VVC) announced that it will be jointly bidding on a 30-mile FERC 1000 competitive transmission project in MISO with PSEG. While this is a small project this shows that (1) PEG is still committed to competitive transmission after the protracted Artificial Island process and (2) management is open to partnering with more local utilities to improve the probability of success. The project connects to a Vectren substation in Indiana and was identified by Vectren to MISO. The deadline for bid submissions is July and a winner is expected to be disclosed in December. We ultimately expect a large number of bidders to participate as utilities continue to 'test the waters' with respect to FERC 1000 implementation.

Penn East is now expected to be completed by YE18 versus YE17 previously.

Below we present our EPS estimates which are unchanged in the near-term following the recent Analyst Day refresh.

[illegible]

Source: Company Filings, FactSet, and UBS Estimates

Our valuation is based on a 2018E sum-of-the-parts analysis where we apply an EV/EBITDA multiple to the Power subsidiary and P/E for the utilities. In our recent upgrade note we increased the premium for the regulated utility to 1.0x-turn P/E from 0.5x-turn previously.

Sum of the Parts Analysis - Hedged Analysis - UBSe							
All figures in USD millions except per share	2018E Adj.	EV/EBITDA & P/E Multiple			Enterprise Value		
	EBITDA	Low	Base	High	Low	Base	High
PSEG Power	1,441	6.0x	8.0x	9.0x	8,645	11,527	12,968
Energy hedging normalization (adjust to open EBITDA)	(158)	6.0x	8.0x	9.0x	(947)	(1,262)	(1,420)
Capacity price normalization @ \$160/MW-day	(145)	6.0x	8.0x	9.0x	(869)	(1,159)	(1,304)
Hhalf-year Keys & Sewaren CCGTs online in mid-2018 (discounted at 8% to '18)	90	6.0x	8.0x	9.0x	541	721	811
Bridgeport harbor CCGT online in 2019 (discounted at 8% to 2018)	54	6.0x	8.0x	9.0x	324	432	486
PSEG Enterprise /PSEG LI (LIPA)	57	4.0x	6.0x	7.0x	228	341	398
<b>Total EV on adjusted open EBITDA</b>					<b>7,922</b>	<b>10,600</b>	<b>11,939</b>
Add: NPV @ 8% 2018-2020 Energy Price Hedging						158	
Add: NPV @ 8% 2018-2020 PS Premium Capacity Pricing over \$160/MW-day						520	
Subtract: Net Debt						(3,407)	
<b>NPV of Power and Non-Reg Equity</b>					<b>5,193</b>	<b>7,871</b>	<b>9,211</b>
Number of Shares Outstanding (2018E)					508	508	508
<b>Power &amp; Holdings Equity Value per Share</b>					<b>\$10.22</b>	<b>\$15.49</b>	<b>\$18.13</b>
	2018 Net	P/E Multiple					
	Income						
PSE&G Net Income	997	15.3x	17.3x	18.3x	15,208	17,203	18,200
	Peer Multiple =		16.3x				
	Premium/Discount =		1.0x				
Number of Shares Outstanding (2018E)					508	508	508
<b>PSE&amp;G Equity Value Per Share</b>					<b>\$29.94</b>	<b>\$33.86</b>	<b>\$35.83</b>
<b>Total Equity Value per Share</b>					<b>\$40.00</b>	<b>\$49.00</b>	<b>\$54.00</b>

Source: Company Filings, FactSet, and UBS Estimates

## SCANA Corp.

*We see an in-line quarter with most of the discussion focussed on the upcoming fixed-price option decision and the recently filed gas ratecase in North Carolina.*

We estimate in-line 1Q16 EPS at \$1.41 vs consensus \$1.43. Weather added \$0.05 to earnings in 1Q15 and we assume a milder 1Q16 for a net -\$0.03 year over year. We expect to see only -\$0.01 from remaining 1Q dilution from the sale of CGT and SCI offset by hybrid debt paydown (was overall dilutive -\$0.04 for the full year 2015 followed by a projected +\$0.04 accretion in 2016). This is offset by +\$0.07 of higher BLRA revenues for the VC Summer nuclear construction project. O&M is forecast for a 2% increase this year vs 2015. The 2015 depreciation study reduced annual depreciation \$29M, although savings were passed back to customers through 1H15, so we expect a -\$7M decline this 1Q. Interest and dilution reduce YoY comps by another -\$0.03.

**Figure 200: SCG 1Q16E vs 1Q15A Walk**

SCANA Corp. 1Q16 Earnings Walk	EPS
<b>1Q15A Adjusted EPS</b>	<b>\$2.80</b>
Reversing Gain on Sale	(\$1.41)
Weather vs Normal in 1Q15	(\$0.05)
Weather vs Normal in 1Q16	\$0.02
Other Electric Margin & Income	
Sales Growth (co guid -0.2% decline in 2016)	\$0.00
Base Load Review Act (BLRA)	\$0.07
Gas Margin	
E&G Gas Rate Stabilization Case	\$0.00
O&M 2% growth in 2016	(\$0.01)
CGT earned through Jan (not seasonal)	(\$0.01)
SCI sold in Feb	(\$0.01)
Hybrid debt paydown from CGT proceeds	\$0.01
Issued \$500M debt in May 5.1%	(\$0.03)
Tax rates (32% for 2015 and 2016 vs 32% in 2014)	\$0.00
Depreciation	\$0.03
Dilution	(\$0.00)
<b>1Q16E Adjusted EPS</b>	<b>\$1.41</b>
1Q16 Consensus	\$1.43
2016 UBS <sub>e</sub> EPS	\$4.03
2016 Consensus	\$3.97
<b>2016 Guidance</b>	<b>\$3.90-\$4.10</b>

Source: UBS Estimates, Company filings, FactSet

### Expect a decision on the fixed price option for VC Summer in 2Q

Subcontractor Fluor is now on site and helping to assess progress to date as well as the new proposed milestone schedule for the VC Summer new nuclear project. SCG expects to reach a conclusion on the proposed "fixed price" option in 2Q16, which would cost ~\$488M more than the more variable priced amended contractor agreement. Among the factors to be considered will be Fluor's assessment of any possible incremental manpower needs (with higher cost) to achieve the schedule as proposed in the recent settlement with Westinghouse. Once this decision is made, the final settlement schedule and cost estimate will be taken to regulators for approval.

## Estimates unchanged; no credit for higher VC summer spending yet

Our 2016+ estimates remain unchanged and reflect \$29M of lower depreciation offset by continued regulatory attrition as the electric utility stays out of ratecases through peak construction. Guidance for 2016 was maintained on the 4Q call at \$3.90-\$4.10 (internal target \$4.00). We see the utility earning mid-9% ROEs through the next ratecase, helped by lower depreciation.

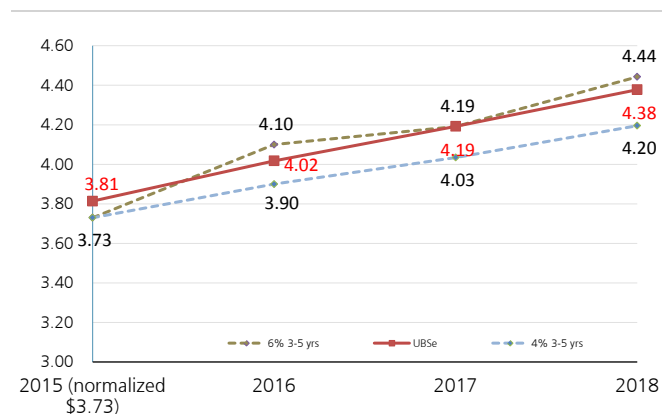
**Figure 201: Comparison of New 2016-2018 Guidance vs Previous Guidance**

Guidance Range	Old Low	Old Mid	Old High		New Low	New Mid	New High	UBSe
2014A (normalized)	3.58	3.58	3.58					
2015 (guidance)	3.60	3.70	3.80	2015A (norm)	3.73	3.73	3.73	3.81
2016	3.80	3.91	4.02	2016 (guide)	3.90	4.00	4.10	4.02
2017	3.91	4.09	4.26	2017	4.03	4.11	4.19	4.19
2018	4.03	4.27	4.52	2018	4.20	4.32	4.44	4.38
	3%		6%		4%		6%	

Source: Company filings, UBS estimates

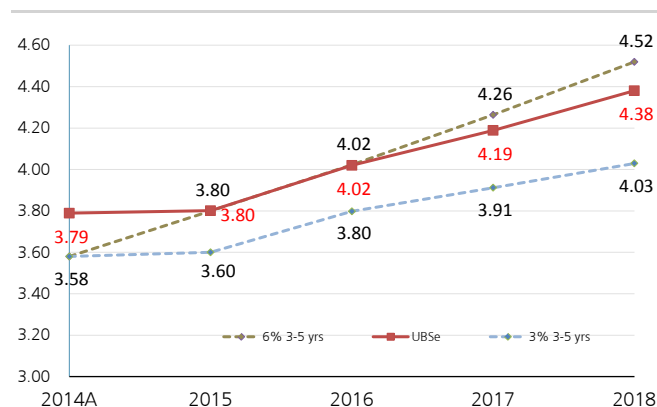
On the 4Q call, LT growth guidance was raised a nickel higher than previous 3-5 year guidance at 4%-6% (vs 3%-6% previously) off a 2015 weather normalized base of \$3.73 and our new estimates with lower depreciation continue to sit toward the top end of this narrowed range for the next two years. While management is conservative on sales with a 0% projection for next year (energy efficiency offsetting any customer and economic gains), our modelling assumes 1% growth.

**Figure 202: CURRENT UBSe vs EPS Implied Guidance from 4%-6% Growth off Weather Normalized 2015A**



Source: Company filings, UBS estimates

**Figure 203: PREVIOUS UBSe vs EPS Implied Guidance from 3%-6% Growth off Weather Normalized 2014A**



Source: Company filings, UBS estimates

## New ratecase filing for PSNC

As expected, the company filed a ratecase for North Carolina gas utility PSNC on March 31, 2016 for \$41.6M (9.7%) based on the currently authorized 10.6% ROE (vs 9.16% TTM) and \$949.3M of ratebase for a 2015 yearend test year. The request is intended to recover pipeline operating costs, implement a pipeline Integrity Management rider, and establish a deferral mechanism for distribution integrity management operations and maintenance expenses. This is the first filing for PSNC in 8 years, during which \$609M of capex was invested with another \$149M expected by June 30, 2016. Ratebase increased \$240M since Dec 31, 2007. The most important part of the filing is the rider, which is intended to

**The most important part of the filing is the rider, which is intended to recover nearly 60% of 2016-2018 capex (see table below).**

recover nearly 60% of 2016-2018 capex (see table below), which is significantly higher than the historic \$75M annual level as the utility expands the pipeline system.

- **PSNC already enjoys a utilization tracker** which offsets the effects of energy efficiency and other volumetric fluctuations, so these additional trackers for pipeline integrity management follow this trend. While no specific spending plan for this has yet been identified. Ratecases every few years will likely be necessary to keep up with the size of the program. As a reminder, PSNC rates are set on a historical test year with 6-9 months to a decision, although CWIP can be updated through the decision. Management notes that the integrity management program costs will not be borne by all customers, with much of the rate increase falling onto industrial customers.

**Figure 204: PSNC Capital Plan, 2016-2018**

PSNC Capex (\$M)	Deferred recovery	Allocated to rider	Total
2016	\$ 94	\$ 106	\$ 200
2017	80	200	280
2018	106	106	212
<b>Total 3-years</b>	<b>\$ 280</b>	<b>\$ 412</b>	<b>\$ 692</b>
	40%	60%	

Source: SCANA

- **No electric ratecases through 2017 despite delay and no block equity through 2018.** With \$400M of after-tax proceeds from the sale of CGT/SCI to D received in 1Q15, management terminated plans to issue any secondary equity in 2015/16. Planned DRiP equity raise remains \$125M for 2017 and \$130M for 2018. Due to the timing of redeployment into VC Summer and other capex, the transaction was -\$0.04 dilutive in 2015 but is expected to turn +\$0.04 accretive by the end of 2016. Management's revised long-term 4%-6% EPS growth guidance (rebased off a weather normalized 2015 \$3.73) is a nickel above previous guidance.
- **SCE&G to file for a gas utility rate adjustment in June.** With the gas utility reporting TTM of only 8.97% (down from 9.77% in Sept), the company plans to file for relief under the Rate Stabilization Act, which allows adjustments when ROE falls outside +/- 50 bps of the authorized 10.25% level.
- **Ratebased distributed solar program.** SCE&G plans to build 95 MW by 2020 (~2% of peak load) in conjunction with Act 236, starting with 10 MW in 2015, with the first 3.8-MW project adjacent to corporate HQ. The overall target is split roughly 50/50 between utility and non-utility (commercial/residential).
- **Preparing wider solar efforts:** Consistent with peers like SO, management had been poised to get *more* involved in solar investments even when an ITC expiration looked imminent for yearend 2016. With the 5-year extension of tax credits, we see increased merit for a ratebase approach in SC to be adopted in ~2017 timeframe under .Act 236

**Planned DRiP equity raise remains \$125M for 2017 and \$130M for 2018.**

**More integrity spending, driving ups capex outlook**

As noted in the table below, the electric utility earned a 9.75% ROE for the trailing 12 months ending Dec 2015, still above management's stated goal of achieving at least 9% or higher in order to avoid non-BLRA base rate increases during peak

nuclear construction years. The settlement approved in Sept to deal with VC Summer nuclear construction cost increases and delays also includes a lower BLRA ROE of 10.5% beginning in 2016 vs the previous 11.0% authorized. We note another possible ROE haircut to get the higher cost estimates under the recent settlement with Westinghouse approved as well, but still expect to see EPS toward the upper end of the range.

**Figure 205: Earned ROE vs Authorized, 2Q13-4Q15**

Reporting Qtr	Regulatory Earned ROE (TTM)				Retail Ratebase (\$M)				Wtd Avg ROE
	SCE&G Elec	VC Sum	SCE&G Gas	PSNC	SCE&G Elec	VC Sum	SCE&G Gas	PSNC	
Authorized	10.25%	11.00%	10.25%	10.60%					
Dec-15	9.75%	11.00%	8.97%	9.16%	\$ 4,995	\$ 3,214	\$ 542	\$ 841	10.07%
Sep-15	9.70%	11.00%	9.77%	9.18%	\$ 4,989	\$ 3,214	\$ 540	\$ 825	10.10%
Jun-15	9.51%	11.00%	10.01%	9.86%	\$ 4,966	\$ 2,667	\$ 532	\$ 815	10.01%
Mar-15	9.60%	11.00%	9.42%	10.18%	\$ 4,935	\$ 2,667	\$ 521	\$ 806	10.06%
Dec-14	10.00%	11.00%	9.42%	9.92%	\$ 4,898	\$ 2,667	\$ 521	\$ 805	10.26%
Sep-14	10.00%	11.00%	10.54%	11.34%	\$ 4,936	\$ 2,667	\$ 507	\$ 723	10.44%
Jun-14	10.00%	11.00%	10.94%	11.45%	\$ 4,944	\$ 2,106	\$ 501	\$ 715	10.44%
Mar-14	10.20%	11.00%	10.69%	11.31%	\$ 4,933	\$ 2,106	\$ 499	\$ 718	10.53%
Dec-13	9.50%	11.00%	10.69%	11.31%	\$ 4,901	\$ 2,106	\$ 499	\$ 718	10.11%
Sep-13	9.70%	11.00%	10.68%	11.94%	\$ 4,902	\$ 2,106	\$ 492	\$ 694	10.28%
Jun-13	9.90%	11.00%	10.12%	11.55%	\$ 4,965	\$ 2,106	\$ 485	\$ 695	10.33%

Source: Company filings

### Higher spend = higher ratebase, if deemed prudent.

We have not yet reflected any possible benefit from higher nuclear capex and CWIP pending the final outcome of negotiations with the consortium (i.e., whether the company picks a fixed-cost option). We continue to see some incremental pressure to 2017 and 2018 EPS projections on the back of the delayed nuclear schedule and avoidance of rate cases, with continued need to maintain cost controls while the project construction is ongoing.

**Figure 206: UBS Estimates for SCG, 2014A-2018E**

	2014A	2015E	2016E	2017E	2018E
SCE&G	\$ 3.23	\$ 3.41	\$ 3.37	\$ 3.47	\$ 3.70
PSNC	\$ 0.39	\$ 0.41	\$ 0.44	\$ 0.49	\$ 0.50
Other	\$ 0.17	\$ (0.01)	\$ 0.21	\$ 0.23	\$ 0.18
<b>Consolidated</b>	<b>\$ 3.79</b>	<b>\$ 3.81</b>	<b>\$ 4.02</b>	<b>\$ 4.19</b>	<b>\$ 4.38</b>
CAGR vs 2015 weax norm \$3.73					5.5%
Guidance Range			3.90-4.10		
Prior UBSe	\$ 3.79	\$ 3.81	\$ 4.02	\$ 4.19	\$ 4.38
Street Consensus	\$ 3.79	\$ 3.81	\$ 3.97	\$ 4.17	\$ 4.43
Long-Term Guidance			4%-6% L-T EPS growth off 2015 normalized \$3.73		
High 6%		\$ 3.73	\$ 4.10	\$ 4.19	\$ 4.44
Mid 5%		\$ 3.73	\$ 4.00	\$ 4.11	\$ 4.32
Low 4%		\$ 3.73	\$ 3.90	\$ 4.03	\$ 4.20

Source: UBS estimates, Company filings, FactSet

## Putting the SCANA Story Together

We are increasingly constructive on SCANA's ability to execute on both its nuclear construction program given the clear potential for a fixed price deal with its new counterparties, Westinghouse (backed by parent Toshiba), as well as broader backdrop for demographic trends in South Carolina. Management continues to reflect conservative assumptions of 0% load growth in 2016 – and raised its long-

**Mgmt executes in all the right ways – expectations already at high end of range though.**

term growth rate with 4Q to 4-6%, up from a wider 3-6% range previously. We see this new range as consistent with other regional peers. That said, we and Street *already* reflect EPS estimates towards the higher end of the range.

### **Can the multiple expand further? Possibly.**

The question remains how 'derisked' can it truly get this project? While we're increasingly constructive on the project overall, the real questions come back to risks around electing bonus depreciation for both units (even if at a lower level in 2018 and 2019) equal to ~\$0.30 of EPS in a worst case, as well as credit risks around Toshiba's declining credit quality. Note further delays to the project could slip it down to lower tiers of eligibility with bonus depreciation, suggesting at least for equity investors, less risk on timeline than had previously existed. We suspect this concern could continue to linger in the near-term. We also see some nascent risks around timeline for its critical path item around the shield building, but suspect this is more of a modest risk relative to the prior concerns.

### **The story is about execution – without failures.**

Should management simply be able to continue to execute on its project into 2018, the story will re-rate. Risks will also increasingly shift in the coming year towards discussion of in-service criteria and execution into 2018 of achieving in-service criteria. These have not been trivial for other recent more complicated new power plants (Edwardsport, Kemper, etc). Bottom line, we see risk, but real and logical reward to re-rate upon execution. The stock has already taken a significant step up – and could yet have another slow-and-steady step up in the coming couple years.

- **Toshiba = what are the credit guarantees?** Management tried to talk down concerns over its counterparty exposure to Toshiba via Westinghouse. It emphasized that Toshiba intends to stay in the nuclear business, and specifically has retained the same individuals to work on the project. Speaking to the current financial status at Toshiba, management emphasized that despite the triggering of security provisions in the contract, it could continue work even if bankruptcy at its counterparty were to occur (with intellectual property put in escrow enabling other parties to theoretically execute on the work) – and further – had already begun a process on security claims given recent credit downgrades at Toshiba. We see this as an emerging concern for the project worth monitoring.
- **Shield Building Panels = Next Critical Path item garnering attention.** SCG noted in its recent reports and on the call its latest focus remains a mitigation strategy around timing of delivery of panels for its shield building from NNI (Newport News Industrial) for shield panels. Installation thus far is going a bit better than expected, but receipt of sub-modules is the piece closely watched by the company.

### **Focusing on the Nuclear (Fixed Price) option.**

Per the recently announced settlement between the owners of the VC Summer new nuclear units and Westinghouse Electric Company (WEC), SCG has 12 months from Nov 1 to choose between the amended EPC contract and the fixed price option. With respected subcontractor Fluor now on the ground and helping to assess the situation, we expect SCG to present a recommendation to the Public Service Commission and the separate Office of Regulatory Staff in 2Q16 once a new milestone schedule is produced (max five months but probably sooner).

**We see multiple expansion upon election and approval of the fixed price option.**

**Substantial further re-rating should come in time – as the first unit successfully reaches in-service**

**We see this as an emerging concern for the project worth monitoring.**

**With respected subcontractor Fluor now on the ground and helping to assess the situation, we expect a recommendation on the fixed price option in 2Q16.**

While the fixed price option would reduce owner's financial risk through completion, the \$488M incremental cost vs the more variable priced amended EPC contract requires the consideration of future interest rate risk and the probability of contractor out/under performance, amongst other factors. However, while regulators will take up to six months to approve either decision, the company need not necessarily have approvals prior to the Nov 1 option expiration since choosing the fixed price option would be subject to regulatory approvals anyway, providing a regulatory out in the event of rejection. In any event, we believe it's also possible that SCG may choose the fixed price option even without a regulatory blessing if that route is judged to be in the shareholder's interest. Regardless, SCG would always remain exposed to owner's costs on delays at \$10Mn/mo.

Once the fixed price option is elected (with ~2Q), we would expect management to revise formal capex projections upwards to add in the additional cost of this arrangement. This would drive a positive impact to formal estimated capex and CWIP budgets from the project. The latest disclosures only reflect the amended project.

**Prior regulatory settlement needs to be amended – likely with a cost.** As noted below, the company's September regulatory settlement essentially preapproved costs up to \$6.827B (SCG's 55% share including inflation and interest expense) with a 50 bps haircut to 10.5% for prospective CWIP. We would expect these options provided by the new settlement with Westinghouse to likely require further ROE haircutting for the \$286M-\$788M higher pricing. In any event, once the units are in service, they will be folded into ratebase at the authorized ROE, which currently stands at 10.25%. The company is intentionally avoiding the next electric ratecase filing until after peak capex years (2016 and 2017), but we would eventually expect one to be filed in the 2017 timeframe for 2018 implementation. Management remains highly confident of ability to maintain earned ROEs above 9.0% through the next ratecase, with 9.7% earned over the TTM.

**Bonus depreciation extends block equity deferrals through 2018.** Management continues to forecast ~\$75M of annual deferred tax benefit from the 5-year extension of bonus depreciation rule, which helps defer block equity issuances through at least 2017. There are still plans to issue \$125M of DRiP equity in 2017 followed by \$130M of DRiP in 2018. However, the company also indicated that choosing the fixed price option at an extra cost of \$488M above the more variable priced amended settlement could result in higher equity needs after 2016. Furthermore, with VC Summer Units 2 and 3 expected to meet guaranteed substantial completion dates of August 2019 and August 2020, it's possible that these units could qualify for 30% bonus depreciation as well.

The new units should qualify for bonus depreciation at lower levels. With the rate at 40% and 30% respectively in 2018 and 2019, the in-service of the plants could well be impacted by bonus depreciation, limiting the ratebase uplift presented by these projects – albeit meaningfully providing a cash flow benefit. Mgmt remained unclear as to whether they would qualify; we suspect this is likely the case. Is it embedded in the base plan and 4-6% update? No. While a risk within the range, we suspect mgmt would not have increased the range of late, knowing full well the risk to ratebase and utility earnings from eventually electing bonus depreciation from these assets.

How much could it be? With each unit roughly ~\$7 Bn (~50% ownership), and a blended bonus depreciation rate of ~35%, we estimate the bonus depreciation

Choosing the fixed price option at an extra cost of \$488M above the more variable priced amended settlement could result in higher equity needs after 2016.

Bonus D on new nuclear units is not in the 4-6% plan, but is likely informally contemplated

impact could be nearly ~\$900 Mn in a maximum case, translating to ~\$0.30 in EPS in a worst case scenario. That said, the uncertainty in mgmt's response suggests other tax strategies could yet be evaluated. That said, it remains clear it will pursue the most ideal avenue for the customer.

*For further context, please refer to our recent notes:*

[2/22/16 Considering the Options](#)

[11/4/15 Reducing Risk on all Fronts](#)

[8/20/15 Demand Growth Paints Paler Pic of Economy](#)

[8/5/15 Settling a Nuclear Deal](#)

[6/30/15 A Sweeter Summer](#)

[5/3/15 Bearing the Strain](#)

[3/13/15 Atomic Alterations](#)

[2/23/15 Tough Talks for Nuclear Delays](#)

## What else is important for SCANA?

- **Settlement Announced with Westinghouse for the VC Summer nuclear project, and includes a fixed price option.** The settlement was concurrent with the recent announcement of Westinghouse Electric Company's (WEC) acquisition of the nuclear construction business of project partner Chicago Bridge & Iron (CBI). SO's litigation with Westinghouse was also resolved concurrently for the construction of Plant Vogtle and both managements are optimistic that the consolidation of the partnership into a single entity under new (potentially fixed price) contracts will reduce the likelihood of future construction delays, cost increases, and disputes. The VC Summer settlement supersedes the Consortium's previous revised schedule and cost estimate, which was never accepted by SCG in the first place as final and accurate. Thus, SCG's prior opinion that the revised schedule included at least \$411M of disputed cost increases (see our "[Atomic Alterations](#)" and "[Bearing the Strain](#)") is now also superseded by the new agreement, which includes the following provisions:
  - **A few extra months.** The guaranteed substantial completion dates for Units 2 and 3 are pushed out a couple of months to August 2019 and August 2020, respectively.
  - **Increased cost estimate.** Capital costs (SCG's 55% share) are increased by \$245M to \$5.492B over the estimate in Order 2015-661 that was approved last month to achieve regulatory buy-in for changes to the original schedule and estimates (see below for details). Escalation to Westinghouse is increased \$19M to \$813M. Total expected project cost (SCG's 55% share) is increased \$286M to \$7.113B over Order 2015-661. The earlier regulatory settlement came at a price of 50 bps reduction to the authorized ROE (to 10.5%) for the project during construction. Since this settlement envisions even higher costs, another haircut is possible for regulatory approval, although we note that estimates would likely remain toward the top end of 3%-6% during construction and that once in service, the plant would be folded into ratebase under consolidated metrics anyway (currently authorized 10.25% ROE).
  - **Higher damages provision.** SCG's 55% of the liquidated damages provision is increased significantly from \$86M to \$509M.

If elected, the fixed price option would cost 11% more than the original estimate. SCG and Santee Cooper will be reviewing over the next several months before bringing the results to Staff for a possible formal regulatory filing.

Another project ROE haircut from 10.5% during construction is possible to get regulatory approval, but in any event, we still see achievement of the upper end of 3%-6% through the interim construction period after which the plant is folded into ratebase anyway (currently authorized 10.25%).

- **Bonuses** were eliminated for final capacity performance and replaced with a \$303M (SCG's 55%) bonus pool for milestone completion.
- **Attempting to eliminate future disputes** over cost allocation between owners and contractors, the change-in-law provisions in the contract were explicitly defined as "Formal written adoption of a new statute, regulation, requirement, or code or new NRC regulatory requirement that did not exist as of this amendment."
- **A unilateral choice fixed price option** is also available to owners SCG and Santee Cooper, which costs an extra \$488M (SCG's 55% of total project cost \$7.601B) to eliminate the risk of future increased contractor costs. This represents an 11% increase over the original project estimate of \$6.827B (SCG's 55%). Liquidated damages are reduced to a \$372M cap (SCG's 55%) and milestone bonuses are still paid but the pool is reduced to \$165M (SCG's 55%). Both owners are reviewing this option over the next several months and once the evaluation is complete (including an assessment of future interest rates), the results will be discussed with Staff before making a formal filing with the Public Service Commission of South Carolina.
- **Expect the development of a new revised construction payment milestone schedule over the next several months.** Through March/April or until a new schedule is agreed upon, owners will make \$100M monthly payments to the Consortium (SCG share \$55M). Thereafter, payments are made based on the achievement of milestones on time. In the event the fixed price option is elected, all payments made through the date of election are credited 100% towards that option. The company expects a significant update to the CAPEX and CWIP tables once the new schedule is finalized.
- **Risks are reduced, but still some remaining.** Note that in the event of further delays (under any option), owners would still incur the cost of onsite personnel and insurance, which SCG estimates at \$10M/mo for their owned interest. However, these owners' costs would also be eligible for liquidated damages as well as possible regulatory recovery (subject to a prudence test) once the project is in service.

**Figure 207: New nuclear CAPEX and CWIP, Recent Quarterly Reports (major update in a few months)**

	2015E	2016E	2017E	2018E	2019E	2020E						
New Nuclear CAPEX (as of Dec 31, 2015)	\$	1,166	\$	1,013	\$	677						
New Nuclear CAPEX (as of Oct 29, 2015)	\$	1,147	\$	959	\$	586						
New Nuclear CAPEX (as of Sept 30, 2015)	\$	752	\$	1,032	\$	959						
New Nuclear CAPEX (as of July 30, 2015)	\$	927	\$	979	\$	899						
Incremental New Nuclear CWIP (as of Dec 31, 2015)	\$	547	\$	812	\$	1,344	\$	939	\$	496	\$	291
Incremental New Nuclear CWIP (as of Oct 29, 2015)	\$	547	\$	1,100	\$	1,138	\$	828	\$	483	\$	349
Incremental New Nuclear CWIP (as of Sept 30, 2015)	\$	547	\$	1,007	\$	1,089	\$	828	\$	440	\$	276
Incremental New Nuclear CWIP (as of July 30, 2015)	\$	597	\$	1,152	\$	948	\$	798	\$	413	\$	253
Reflects CWIP from July 1 through June 30												

Source: Company filings

- **Regulatory risk also pared significantly with a separate settlement approved for project schedule and costs.** On Sep 2, 2015, the South Carolina Public Service Commission (SCPSC) unanimously approved SCG's settlement agreement with the South Carolina Office of Regulatory Staff and the South Carolina Energy Users Committee (SCEUC) that essentially eliminates all contested issues and establishes support for the approval of the revised construction and capital cost schedules for the VC Summer nuclear project under docket 2015-103-E. Parties waive the right to appeal. As noted above, SCG has reached a settlement with the Consortium, which we expect to be received positively as the SCPSC had encouraged the utility to continue to negotiate with the Consortium and take other necessary steps to minimize delay related costs for the benefit of SCE&G's customers.
- **Agreement includes 50 bps ROE reduction; impact begins mostly in 2017.** Settling parties agree to reduce the allowed ROE for VC Summer from 11.00% to 10.50%, to be applied prospectively under the Base Load Review Act after 1/1/16. We estimate this reduces the future revenue requirement by \$15M over a 5 year period, with the -\$0.06 EPS impact beginning after the Nov 2016 rate increase and weighted toward the first two years (peak construction period). As noted above, another ROE haircut is possible in order to get the new settled contract amendments approved under higher cost estimates. However, we would still expect upper end of 4%-6% to be achieved during the interim construction period, after which the project would be folded into ratebase anyway (currently authorized 10.25% ROE).
- **Two intervenors were not parties to the agreement that was approved.** Notably, neither the Sierra Club nor CMC Steel (the other two intervenors to the docket) signed on to the agreement. Recall that in Oct 2014, the SCEUC and the Sierra Club lost a SC Supreme Court appeal of a previous challenge to a \$278M cost increase that had been approved by regulators.
- **Watching the credit ratings: negotiations with consortium have been watched by the rating agencies.** While the utility's debt rating should maintain investment grade levels, management has acknowledged that construction delays are likely to cause some ratings slippage at both the operating company and holding company levels. We expect the announced settlement with the consortium to be received positively. In September, the Holdco was moved to stable from negative outlook at S&P (BBB+) but was moved to negative outlook from stable at Moodys (Baa3). It remains stable outlook at Fitch (BBB-). In the event of further downgrades, management has given the impression that equity issuance to defend the rating would be unlikely as the Holdco won't need to issue or refinance anything until 2020 (emphasizing that operating company debt to fund construction will certainly remain investment grade). In particular, Moodys has highlighted the need to maintain FFO/Debt above 13%, which management has previously seen as unlikely over the next two years. While the BLRA provides for recovery of financing costs during construction, the plants must be in service to begin receiving cash for depreciation. Despite the settlement reached with the Consortium, we think the problem appears to be increasing balance sheet stress caused from this lack of capital recovery during an extended construction period.

We expect the settlement with Westinghouse to be received positively as the SCPSC had encouraged the utility to continue to negotiate with the Consortium and take other necessary steps to minimize delay related costs for the benefit of SCE&G's customers.

Another ROE haircut is possible though in order to get the new, higher costs of the settled contract amendments approved.

- **SCANA Energy (retail natural gas marketing business in Georgia)** remains the regulated provider for the State of Georgia through August, 2017, extending the role it's had since program inception in 2002.
- **The Chinese Analogue.** The Chinese AP1000 units at Sanmen 1 are expected to be in-service by mid-year 2016 and should provide an early indicator of operational confidence in the design of the plants.

## South Carolina economic growth continues modest improvement

Economic growth in the Carolinas and SCG's territory continues to be modest, with unemployment trends in the region (4.7% for SCG jurisdiction) continuing to improve after several years of falling along with the national average, now at 5.0%. Customer growth continues to improve, particularly at the gas LDCs, where SCE&G Gas customers grew 2.7% in 4Q15 (year over year) and PSNC has grown over 2.5% for the past 6 quarters. SCE&G Electric continues to improve more slowly with growth of 1.5%. Accounting for conservation and energy efficiency, weather adjusted total retail electric sales over the trailing 12 months were a 1.3%, with weak industrial growth of -0.5% (down from +2.3% TTM Sept) as a result of the recent flooding in the state. Residential sales continue to march upward at a strong 3.2% and commercial electric sales of +0.8%.

Management continues to forecast a very conservative -0.2% overall retail sales growth for 2016 despite the improvements in recent quarters, citing them as unusual vs the previous two years of data. The company plans to file a new Intergrated Resource Plan in the coming weeks with a new long-term load growth forecast. The previous IRP embedded a 15-year (through 2029) +1.4% net growth projection (+1.7% customer growth offset with -0.3% energy efficiency and conservation) and management doesn't anticipate a material difference in the new filing at this time.

Management continues to forecast a very conservative -0.2% overall retail sales growth for 2016 despite the improvements in recent quarters, citing them as unusual vs the previous two years of data.

**Figure 208: SCANA Customer Growth and kWh Sales Growth %, 1Q13-4Q15**

	Weather Adj Retail kWhs Sales (TTM)				Cust Growth (YoY each Qtr)		
	Residential	Commercial	Industrial	Total	SCE&G Elec	SCE&G Gas	PSNC
Dec-15	3.2%	0.8%	-0.5%	1.3%	1.5%	2.7%	2.5%
Sep-15	1.7%	1.4%	2.3%	1.7%	1.6%	3.1%	2.8%
Jun-15	-0.3%	0.3%	3.8%	1.1%	1.6%	3.0%	2.7%
Mar-15	-2.0%	-0.7%	3.3%	0.0%	1.5%	2.9%	2.6%
Dec-14	-1.2%	0.0%	3.9%	0.6%	1.4%	2.8%	2.5%
Sep-14	-1.1%	-0.1%	4.2%	0.7%	1.3%	2.5%	2.5%
Jun-14	-1.5%	0.1%	3.7%	0.5%	1.4%	2.3%	2.3%
Mar-14	-0.8%	-0.4%	3.3%	0.5%	1.3%	2.4%	2.3%
Dec-13	-2.3%	-1.4%	3.1%	-0.5%	1.2%	2.4%	2.3%
Sep-13	-1.8%	-1.2%	1.6%	-0.6%	1.3%	2.2%	2.0%
Jun-13	0.1%	0.6%	-0.2%	0.2%	0.8%	2.0%	2.0%
Mar-13	2.5%	0.7%	0.5%	1.4%	0.8%	1.8%	2.0%

Source: Company filings

## Valuation: Raise PT \$2 to \$68 for higher peer P/E multiple; Maintain Neutral

We continue to value SCG on a SOTP basis, applying a discount to the 2018E peer utility P/E.

- Our discount for SCE&G remains -5% for continued major construction risk with peak spending years 2017/18 still ahead, despite the improved regulatory risk profile from the BLRA settlement and the announcement of a comprehensive settlement with the construction consortium to resolve all prior disputes over higher costs and delayed scheduling and provide a fixed-price option.
- Unregulated SCANA Energy Georgia remains valued at 5X 2015E EBITDA. As we've noted previously, utility operations outside of the nuclear project have been impressive, earning >9.5% ROE with improving customer growth and usage rates).
- Furthermore, despite 1.3% electric sales growth over the TTM, management's guidance for 2016 assumes ~0% kWh sales growth, with customer and economic growth offset by energy efficiency effects. We find this to be exceptionally conservative, with management acknowledging that given more confidence that growth were to materialize from 2015 to 2016, there would be more upside to EPS guidance.

Figure 209: SCG Sum of the Parts on 2018E

Scana										
Sum of Parts										
SCANA Corp Valuation										
Business Segment	Valuation Metric	2018	Low Case Valuation Multiple	(\$s MM) Value	Peer Multiple	Base Case Prem/ Discount	Valuation Multiple	(\$s MM) Value	High Case Valuation Multiple	(\$s MM) Value
<b>Regulated Business</b>										
SCE&G Franchised Electric	P/E	\$3.70	15.2x	\$8,110	16.5x	-5%	15.7x	\$8,377	16.2x	\$8,644
PSNC	P/E	\$0.50	17.0x	1,236	17.5x	0%	17.5x	1,272	18.0x	1,308
<b>SCG Utilities Equity Value</b>				<b>\$9,345</b>				<b>\$9,649</b>		<b>\$9,953</b>
Georgia Retail (Net of Corporate)	EV / EBITDA	\$47	4.0x	\$188			5.0x	\$235	6.0x	\$282
<b>Total</b>				<b>\$188</b>				<b>\$235</b>		<b>\$282</b>
<b>SCG Equity Value</b>				<b>\$9,533</b>				<b>\$9,884</b>		<b>\$10,235</b>
Fully Diluted Outstanding Shares (2018)				144				144		144
<b>SCG Equity Value per Share</b>				<b>\$66.00</b>				<b>\$68.00</b>		<b>\$71.00</b>

Source: UBS estimates, Company filings, FactSet

# Sempra Energy

*We see a miss for the quarter with several negative year-over-year comps, including the pass-through this year of repairs tax benefits, the inclusion of LNG development expenses, the elimination of REX earnings, lower wind expectations, and lower gas prices.*

We estimate that Sempra will report 1Q16 adjusted EPS of **\$1.63 vs consensus \$1.67**, with comparable year-over-year seasonal revenue swings for SoCalGas. At both SDG&E and SoCalGas, we expect flat O&M but a higher effective tax rate (37% vs last year's 32%) due to the effect of passing repairs tax benefits to ratepayers this year. For comparison, full year benefits in 2015 were \$19M at SDG&E and \$40M at SoCalGas. Additionally, the absence of a 1x \$8M (after tax) gas cost incentive award in 1Q15 also negatively impacts the year over year comparison for SoCalGas. In South America, we see continued currency depreciation of about 12%-13% year over year, which is projected to reduce total FY2016 earnings by -\$0.09 to -\$0.11, offset with underlying growth and \$0.05-\$0.07 of lower tax in Mexico for FY2016 as a result of Peso devaluation. Mexican results should also benefit (only slightly in 1Q) from the absence of -\$5M losses in 2015 at the Termoeléctrica de Mexicali CCGT, now held for sale as of Feb 2016. Generally speaking, we continue to flag that through the investment period, IENova does not record AFUDC based on IFRS accounting. In contrast, Sempra is allowed to book more of a gradual earnings increase predicated on development at the SRE Mexico segment. We expect renewables growth to be flattish, noting that in 4Q15, the company reported a -\$5M impact from realized wind conditions, which may be continuing into 1Q. For Natural Gas, SRE is now including LNG development expenses in 2016 ongoing results (vs excluding them in 2015), which is expected to have a FY2016 impact of -\$20M to -\$25M. As a result of the pending sale of Rockies Express (REX), in 1Q16, there will only be 2 months of REX earnings this year, a year over year impact of -\$6M (per month). Lower nat gas prices -\$0.75/mmbtu have an impact at a rate of \$15M net income for every \$1. A 1x -\$27M loss on the sale of REX has already been reported and will be excluded from ongoing results. We also expect lower tax expense at the parent from the decision to reinvest Mexican dividends into the PEMEX transaction.

**Focus is on upcoming Analyst Day (to be held only if a PD in rate case is issued)**

**Figure 210: SRE 1Q16E vs 1Q15 Walk**

SRE 1Q16 Earnings Walk	EPS
<b>1Q15A Adj EPS</b>	<b>\$1.71</b>
SDG&E	(\$0.02)
SoCal Gas	(\$0.07)
<i>Sempra International</i>	
South America	\$0.02
Mexico	\$0.03
F/X Impact	\$0.00
<i>US Power &amp; Gas</i>	
Renewables	\$0.01
Natural Gas	(\$0.06)
Parent	\$0.02
Dilution	(\$0.01)
<b>1Q16E Adj EPS</b>	<b>\$1.63</b>
<b>1Q16E Consensus</b>	<b>\$1.67</b>
<b>2016 Guidance</b>	<b>\$4.80-\$5.20</b>
<b>2016 UBSe</b>	<b>\$5.00</b>
<b>2016 Consensus</b>	<b>\$5.07</b>

Source: Company Filings, FactSet and UBS Estimates

*For additional context, please refer links to relevant recent reports below:*

[4/1/16 Sticking to Their Guns](#)

[2/29/16 Pivoting Towards Best-in-Class Income Growth](#)

[11/5/15 Poised to Hoist Growth Again](#)

[9/15/15 Still Beating Best-In-Class Expectations](#)

[8/7/15 Exuding Confidence](#)

[7/6/15 Watching the Sparks and Sparklers \(page 8: "The Next Round of California Capex"\)](#)

[6/19/15 The Northern Opportunity](#)

[5/7/15 It's Going To Be More MLP-Like, After All](#)

[4/6/15 Gassing Up for 11% Growth](#)

[3/16/15 Revitalizing the Mexican Midstream Opportunity](#)

[3/10/15 Supersizing Semptra](#)

[12/17/14 Lost El Encino II Bid Still plenty of growth projects ahead, despite some likely delay](#)

[12/10/14 Limited Risk of Slipping on an Oil Spill](#)

[11/26/14 Full Steam Ahead for Cameron](#)

[11/20/14 The Other Side of the LNG Debate \(Incl. Conf Call Transcript\)](#)

## **2016 guidance unchanged vs a year ago, but now includes a dime of LNG costs**

On the 4Q call in Feb, formal guidance for 2016 was initiated at \$4.80-\$5.20, unchanged from the long-term guidance through 2019 that was released a year ago. We had expected a \$0.15 increase for guidance, with \$0.05 from the Pemex deal and \$0.10 lower taxes on repatriation, but this now appears to be offset with \$0.05-\$0.07 lower natural gas pricing, -\$0.04 higher interest, -\$0.04 net FX, -\$0.02 unfavorable wind forecast, and only +\$0.02 from Pemex.

Guidance now includes updated assumptions for the GRC settlement (final decision expected in 2Q16) and \$0.08-\$0.10 of LNG development cost, which had been excluded from adjusted results thus far (was -\$0.04/sh in 2015). Should the project move forward, we expect future costs to be largely capitalized. We were surprised by how positive the developments were on the call with moving to a direct contracting decision rather than initial Memorandum of understanding (MOU) on contract terms; this would appear driven to avoid added costs. Based upon conversations with investors, the consensus appears to be that investors are ascribing minimal value for the project.

Our 2016-2019 EPS estimates reflect the elimination of REX earnings, only slightly offset by interest on the \$440M cash proceeds (no reinvestment is yet assumed). Below we show our estimates vs consensus along with a comparison of our estimated segment EBITDA to company guidance as provided at last year's analyst day in March 2015. We've also added a line to show our expectations for revised guidance ranges given the extraction of REX earnings and the roll-forward to a 2016-2020 EPS CAGR. Given that the GRC settlement is subject to pending approval and Pemex deal are yet to be closed, we have not incorporated those changes into our model yet. We are also waiting for further updates on \$2Bn incremental opportunities.

**Figure 211: EBITDA and EPS Guidance vs UBSe and Consensus, 2015-2019**

2015 Analyst Day (March 2015) Base Plan Projections vs UBSe, 2015, 2016, 2019									
	SRE Guidance 2015	2015A	SRE Guidance 2016	UBSe 2016	UBSe 2017	UBSe 2018	SRE Guidance 2019	UBSe 2019	UBSe 2020
SDG&E	\$510M-\$555M	\$572M	\$540M-\$585M	\$561M	\$579M	\$605M	\$600M-\$650M	\$635M	\$666M
SoCalGas	\$360M-\$395M	\$419M	\$360M-\$395M	\$432M	\$435M	\$454M	\$415M-\$455M	\$483M	\$510M
US Gas and Power	\$80M-\$100M	\$81M	\$90M-\$110M	\$33M	\$69M	\$269M	\$470M-\$510M	\$456M	\$463M
International	\$375M-\$405M	\$388M	\$400M-\$430M	\$412M	\$417M	\$446M	\$460M-\$500M	\$470M	\$495M
Parent & Other	-\$200M to -\$170M	-\$152M	-\$200M to -\$170M	-\$175M	-\$182M	-\$182M	-\$180M to -\$150M	-\$200M	-\$210M
Sempra Earnings	\$1,125M-\$1,285M	\$1,308M	\$1,190M-\$1,350M	\$1,262M	\$1,318M	\$1,594M	\$1,765M-\$1,965M	\$1,844M	\$1,925M
Avg diluted shares	252	251	253	252	254	255	257	256	258
EPS	\$4.60-\$5.00	\$5.21	\$4.80-\$5.20	\$5.00	\$5.20	\$6.25	\$7.00-\$7.50	\$7.20	\$7.47
UBS expected revised guidance			\$4.55-\$4.95				\$6.65-\$7.15		\$7.00-\$7.50
Prior EPS				\$5.00	\$5.20	\$6.25		\$7.20	
Consensus EPS				\$5.07	\$5.52	\$6.42		\$7.49	
EPS Growth Rate				-4.0%	3.9%	20.3%			
UBSe CAGR 2016-2020 off the midpoint of expected 2016 revised guidance \$4.76									11.9%
DPS		\$2.80		\$3.02	\$3.27	\$3.53			
DPS Growth Rate		6.1%		8.0% #	8.0%	8.0%			
Guidance		5-6%		8-9%	8-9%	8-9%			

Source: Company filings, UBS estimates, FactSet

## The Existential Identity Question?

We see management as faced with a defining moment at its forthcoming Analyst Day; among the most important updates since it defined the Mexican growth opportunity and its Cameron 1-3 export trains as it faces questions on what the 'next' source of growth is *beyond* the existing outlook through 2019. With shares trading at a three-year relative low on a rolling FY2 P/E-basis, with a particularly jarring moving the Aliso Canyon gas storage leak, management is in a position to redefine the growth opportunity and look past recent challenges.

Good management at a discount: While many investors have historically pushed back on SRE shares as principally too pricey, we see the current downturn as among the few opportunities to invest in what we see as among the best management teams in the sector, with *the* largest projected balance sheet dry powder of any company in our coverage. Management's track record as a first mover in Mexico, LNG exports, LNG imports, and West-to-East gas leaves us comfortable in its financial acumen. With much of the story historically oriented towards gas investments, we attribute part of the recent pressure as affiliated in part to perceived limitations in further gas investments amidst the wider MLP and midstream pullback. We think investors have too narrowly defined *what is Sempra*?

Renewables pivot coming for diversified infrastructure company? Among the identity questions often asked by investors is how will they redefine the growth around EPS opportunities: We perceive a clear rekindling of interest in renewables and electric growth, not just around its remaining solar sites in California (Mesquite, Copper Mountain, and Flat Ridge) but also in Mexico; its ESJ site can accommodate 1.2GW out of 140 MWs today (resolution on its partnership structure is the limiting factor prior to executing on further growth). Moreover, electric growth opportunities remain clear via transmission as well in Mexico and elsewhere. The key question we see here are clearly compressing returns in the solar space for development, notably below those seen in Mexico and for LNG, albeit also a clearly lower risk profile. We look for management to discuss its return ambitions in the context of any such renewed renewable efforts particularly given its limited taxable income appetite at present, which would otherwise make this strategy all the more obvious.

We see this shift back towards electric as also aligning well with California's reaction to the events at Aliso Canyon, which appear to be only further accelerating the move away from fossil fuels (namely gas) towards electric solutions. We look for more definition around this opportunity at its Analyst Day.

### REX sale should help boost 5-yr EPS growth from 2016-2020

ON 3/30, SRE announced entry into a purchase and sale agreement with majority partner Tallgrass to sell its 25% stake in the Rockies Express Pipeline (REX) for about \$440M in cash vs a book value of \$477M on 12/31/15. The transaction is expected to close in 2Q, pending approvals and a right of first refusal and will result in after-tax losses of \$27M plus an additional 1x charge of \$100M-\$120M for the acceleration of expected capacity release losses on current contract terms.

**Despite this optical benefit to the CAGR roll-forward, we expect management to either maintain or exceed the current 11% CAGR, even counting a full year of REX for the 2016 base year.**

### Reflecting the Rex Impact:

At the upcoming analyst day in May, we expect the current 2016 guidance of \$4.80-\$5.20 to be adjusted downward to exclude about \$60M (-\$0.24) of forecasted earnings from Mar-Dec, or an annualized \$70M-\$75M (~\$0.30) of REX earnings. Management's 11% CAGR guidance through 2019 included an additional 700 mcf/d expected to come online in Dec 2016 from the Zone 3 Capacity Enhancement Project, which we figure would have added another 0.03-0.05 at a rate of \$0.20/mcf. In our [3/14 note](#), we had previously noted an expected drop in 2020 earnings as a result of recontracting West-East legacy contracts in 2019 (with Ultra Petroleum recently failing to make payments on its 0.2 bcf/d), although management now says that projected earnings in 2020 are immaterial. *Also clear to us with this sale is that an MLP spin is off the table for now.*

As we note below, all other factors equal, we see the removal of REX from both ends of the 2016-2020 roll forward as roughly 140 bps beneficial to the headline 5-year earnings growth rate. However, even without this optical benefit to the CAGR roll-forward, we still expect management to either maintain or exceed the current 11% CAGR, even counting a full year of REX for the 2016 base year.

### Further asset sale contemplated of gas LDC

We note recent media reports also indicate the company is contemplating selling down its gas LDC business, which could fetch north of \$200 Mn in today's environment with combined Net Income north of \$10 Mn. We emphasize this potential sell-down of its Southeast gas LDC comes amidst recent meaningful premiums paid for such businesses. The question remains what would management do with the proceeds? We suspect *not* a subsequent utility acquisition. We emphasize the original acquisition of the utility had been oriented around corresponding storage assets. It remains unclear if these would be included as well.

**Mgmt says it is a more of a seller than a buyer in the current M&A environment**

**Figure 212: Comparison of March 2015 11% EPS CAGR Guidance vs Update Potential**

Comparison of March 2015 11% EPS CAGR Guidance vs Update Potential		
<u>Current guidance from March 2015 analyst day</u>		
2014A	4.71	4.71
2015 original guidance midpoint (\$4.60-\$5.20)	4.80	4.80
2016 guidance midpoint (\$4.80-\$5.20)	5.00	5.00
2019 guidance \$7.00-\$7.50	7.25	7.25
<b>Guidance: CAGR 2015-2019</b>	<b>10.9%</b>	<b>10.9%</b>
CAGR 2016-2019	13.2%	13.2%
	CAGR w/o	CAGR with
	REX:	REX in
<u>UBSe potential update at May 2016 analyst day</u>		
2014A	4.71	4.71
2015A	5.21	5.21
2016 guidance midpoint minus \$0.24 REX (Mar-Dec 2016)	4.76	5.00
<b>UBS estimate for REVISED range of 2016 guidance</b>	<b>4.55-4.95</b>	
2019 guidance midpoint (\$7.00-\$7.50)	7.25	7.25
2019 guidance midpoint (\$7.00-\$7.50) minus 0.30 REX minus 0.05 for Dec '16 Zone 3	6.90	6.90
<u>UBSe growth from 2019E-2020E</u>		
SDG&E at 5% growth	0.12	0.12
SoCalGas at 6% growth	0.10	0.10
<u>US Gas &amp; Power</u>		
Cameron 1-3 Guidance \$300M-\$350M in 2019, flat for 2020	0.00	0.00
Renewables	0.03	0.03
<u>International at 5% growth</u>		
Mexico at 5% growth	0.05	0.05
South America at 5% growth	0.05	0.05
UBS estimate for midpoint of 2020 guidance	7.25	7.25
<b>UBS estimate for management's roll to CAGR 2016-2020E</b>	<b>11.1%</b>	<b>9.7%</b>
<b>UBS estimate for INITIATED range of 2020 guidance</b>	<b>7.00-7.50</b>	<b>7.00-7.50</b>
<b>UBSe 2020E</b>	<b>7.47</b>	<b>7.47</b>
<u>Other factors:</u>		
Upside from the reinvestment of \$440M REX sale proceeds and other cash flows	For comparison only; includes REX EPS in 2016 - Including factors on left, still see mgmt able to forecast >11% even on this basis .	
Upside GRC settlement at rates higher than that embedded in 11% base guidance		
Downside Cost of Capital ratecase in 2017 for Jan 2018 rates		
Downside any drag from unrecovered Aliso Canyon penalties		
Upside/downside from DRP/PSEP utility capex vs current 2015-2019 plan driving 11%		
Upside from LNG, Mexico, Renewables not embedded in 11% base guidance		

Source: Company filings, UBS estimates

### Fully reflecting the Cameron 1-3 uplift through 2020

We also expect the 5-year roll-forward to 2016-2020 to more fully reflect the initial LNG export uplift (Cameron Trains 1-3) and upside from the recent ratecase settlement (still pending approval). The current 2015-2019 guidance is for 11% "base" EPS growth off the previous 2015 guidance of \$4.60-\$5.00. Actual 2015 results were much higher at \$5.21, but included ~\$0.30 of tax benefits that are expected to be absorbed in the pending general ratecase (GRC). As such, the current 2016 guidance of \$4.80-\$5.20 is consistent with 11% growth off an adjusted 2015 guidance midpoint minus this ~\$0.30. We further note that the implied CAGR from the midpoints of 2016 guidance and 2019 guidance is 13.2%.

As we illustrate in the table above, the expected 2020 -\$0.35 cliff in 2020 REX earnings would have reduced the 2016-2020 CAGR to ~9.8%. However, with the sale of REX and the removal of \$60M earnings (\$0.24/sh) from the 2016 base year, we see the potential to maintain an 11.1% CAGR, absent other factors such as reinvestment of the \$440M proceeds from the REX sale. Further adding to potential growth, the ratecase settlement (pending 2Q approval) embeds revenue

**We understand EPS will continue to improve from Trains 1-3 as debt amortizes**

requirements above that assumed in the 11% guidance. As we've noted previously, we suspect this may prove to be the highest 5-year CAGR through the foreseeable future; key to any further acceleration remains incremental contract awards for the ~2021 period, particularly for the Cameron 4 LNG opportunity (where ROEs are likely to remain in the 20's on LNG export tolling arrangements). With the historical execution of a 14% CAGR in recent years and utility yield all the more en vogue, we suspect mgmt may well shift towards an explicit target in an effort to provide investors with a clear value proposition (particularly if LNG export opportunities are less likely to pan out).

### **Dividend growth rate raised to get "closer to" expected EPS growth**

The company raised the dividend this year by 8% to \$3.02 (vs previous 6% raises) and further boosted the dividend growth target to 8%-9% from the previous ~6% in order to more "closely align" dividend growth with the 11% earnings growth experienced in 2015 (adjusted). Management did not intend to imply that the two growth rates were "tied together" or explicitly converging at numbers well below 11%. We emphasize a clear potential for an acceleration of this trajectory *above* the EPS growth rate given a potential slowing in EPS growth opportunities. With the payout at 60% on 2016, we see latitude for further increases.

**We see a downside case in which div growth exceeds EPS growth**

### **What's in and what's out in the base plan for 11% EPS CAGR**

Projects that are included in SRE's base plan and support 11% adjusted EPS growth from 2015 through 2019 include \$15Bn approved balance sheet capex, \$4.4Bn JV project capex and \$300-\$350M of contribution from its Cameron Trains 1-3 in 2019. It does not include proposed GRC settlement for the CA utilities (which would have a positive impact above 11% if approved) and potential LNG development opportunities (Cameron expansion, Port Arthur, and ECA liquefaction). Additionally, mgmt. highlights financing requirements for the base plan does not require any equity issuances and MLP financing or formation plan.

**Figure 213: Base Plan Projects 2015-2019 and Development Opportunities Through and Beyond 2019**

Total \$14.7B "On-Balance Sheet" Base Plan plus \$4.4B "Off-Balance Sheet" Joint Venture Financing, 2015-2019					
California Utilities	\$11,800M	Latin America	\$1,500M	Sempra Gas & Power**	\$1,400M
Base Capital		Ojinaga - El Encino Pipeline	\$300M	U.S. Gas Midstream	
SDG&E	\$5,800M	Sonora Pipelines	~\$500M	Cameron Liquefaction 1-3*	
SoCal Gas	\$6,000M	Los Ramones Norte*	~\$350M	Cameron Interstate Pipeline	
Pipeline Safety Enhancement Plan		Ethane Pipeline*	\$165M	Rockies Express Pipeline Expansion*	
Advanced Meter		ESJ Wind Project Phase I*	\$150M	Rockies Express Pipeline	
FERC Substations		Eletrans I Transmission*		East-to-West Service*	
Aliso Canyon Compressor		Eletrans II Transmission*			
Natural Gas Product Offerings		Peruvian Transmission	\$150M	Cameron Liquefaction 1-3 JV OBS funding	\$3,900M
Cleveland National Forest					
North - South Pipeline Development		International JVs OBS funding	\$500M	U.S. Renewables	
Master Meter Mobile Home Park		(includes JVs with Pemex and SAESA)		Copper Mountain Solar 3*	
Voltage Support and Stability				Copper Mountain Solar 4	
Sycamore - Penasquitos					
* Capital to be funded by JV entities not included in the \$14.7B, but does include Sempra's equity contributions.					
** Includes \$100M of Parent & Other capex					

\* Capital to be funded by JV entities not included in the \$14.7B, but does include Sempra's equity contributions.

\*\* Includes \$100M of Parent & Other capex

Total \$7B-\$8B Development Opportunities 2015-2019 Above Base Plan				
California Utilities		Latin America		Sempra Gas & Power
2015-2019	\$1,400M-\$1,750M	2015-2019		U.S. Gas Midstream 2015-2019
SDG&E	\$500M-\$750M	Additional Gas Pipelines (max oppt'y)	~\$11,000M	LNG Related Storage (LA Storage 19 bcf)
SoCal Gas	\$900M-\$1,000M	Expand ESJ Wind Project (~1000 MW)		Pipelines and Petrochemicals
North - South Pipeline 2017-2019	\$800M	Further JV Growth		Port Arthur Pipeline Header
Additional PSEP		Additional Hydro		
Advanced Energy Storage		Additional Electric		U.S. Gas Midstream Beyond 2019
Vehicle Grid Integration		Transmission in Chile		Additional cap on Cameron 1-3
Master Meter Mobile Home Park		Greenfield Power Generation		Cameron Trains 4 - 5
Additional T&D		Liquids Infrastructure		Port Arthur
Incremental Natural Gas Offerings				
Smart Meter Applications		Beyond 2019		U.S. Renewables 2015-2019
		ECA Liquefaction		Solar Projects (Expand Mesquite 530 MW)
Beyond 2019				Wind Projects (Expand Flat Ridge >200 MW)
DG Grid Enhancements				
Additional PSEP				U.S. Renewables Beyond 2019
Alternative Fuel Investment				Battery Storage and Peakers

Source: Company analyst day presentation, March 2015

## Settlement for SDG&E/SoCalGas rate case should allow beat of 11% EPS CAGR

We expect a decision to approve the settlement from regulators in 2Q16. On Sept 11, the company reached a settlement with a majority of interveners in its 2016 General Rate Case (GRC). The settlement resolves all material issues except for the treatment of repairs allowance income tax benefits, with one intervener arguing for a flow through to customers while the company argues that would be inconsistent with historical precedent (the final order is expected to resolve this). Specifically, the proposal suggested the tax benefits from 2011 through 2014 associated with repair expense allowances of \$93M and \$92M for SDG&E and SoCal gas, (\$185M altogether), respectively to be deducted from the rate base retroactively. The proposal, if approved will impact future revenue requirement of SRE. Additionally, SRE was asked to set up a memorandum account for 2015 tax benefits associated with repair expense allowances, amounted to \$50M after-tax YTD that will impact 2015 but will not be deducted from the rate base.

- **Overall, the settlement would grant** \$1.8B and \$2.2B 2016 revenue requirements for SDG&E and SoCalGas, respectively, with 3.5% attrition increases for both 2017 and 2018. More importantly, the revenue requirements include non-refundable portions (not subject to recovery

**We expect the settlement's mid-3%'s increases to have a materially positive effect on long-term CAGR vs the 11% guidance.**

**We also note that this news is compounded by other positive impacts to original guidance, such as the Pemex JV acquisition, renewables growth, and pipeline wins at IEnova, none of which had been included.**

through balancing accounts) of \$1.747B (3.4% higher than 2015 \$1.69B) and \$1.914B (3.7% higher than 2015 \$1.846B), for SDG&E and SoCalGas, respectively. This is directly comparable to company guidance from analyst day for an 11% EPS CAGR from 2015 through 2019 based on 2.75% increases in the non-refundable portion (and for attrition increases). As such, we expect the settlement's mid-3%'s increases to have a materially positive effect on long-term CAGR vs the 11% EPS guidance.

- **Additionally, SDG&E and SoCal reached a 2nd settlement agreement with ORA for a 4-year GRC term**, which will set the attrition adjustment at 4.3% in 2019 both for SDG&E and SoCal, respectively, subject to pending 1st settlement and CPUC approvals.
- **Expecting a PD in the ~March timeframe: Come and gone?** With the Aliso canyon asset now firmly behind the company, we see few reasons for a delay in the Proposed Decision from the CPUC given the existing rate settlement. We understand the new structure already contains substantial new integrity investment management to address concerns around wells. We're not concerned *still* – and investors are 'used' to delayed decisions on rate cases as we are presently seeing. We continue to anxiously await news on the rate case this Spring; we note among the several reasons to delay the Analyst Day into late May was to provide ample latitude to reflect the rate case outcome. Similarly, we note PG&E continues to await a PD on its pending GT&S case; we see customer rate impacts as likely the most meaningful factor.
- **We continue to expect a separate case to address further spend.** We continue to expect a further OII to be launched around gas safety, with potential for separate and additional safety spend to come out of this. That said, the key risk related to Aliso is the total magnitude of unrecoverable expenses, particularly if required to address overall system safety. The timeline for the subsequent OII could well extend into next year; we think this will remain the key lingering uncertainty to shares.
- **Operational future of Aliso Canyon is a key question:** Management is clear they will attempt to save the asset given the substantial benefits provided to ratepayers of operations at this storage facility following initial reports the asset could be permanently closed.
- **Little to no impact on the General Ratecase (GRC) seen from bonus depreciation.** Consistent with past statements, the company expects no impact from the recent extension of bonus depreciation on GRC capex. Recall that previously, we had expected a \$10M-\$15M negative impact on earnings at each utility for 2016 under a 1-year extension, or about \$20M-\$30M in total (about a dime EPS). We note that about 60% of the impact is related to California-jurisdiction assets while the remaining 40% is subject to FERC jurisdiction. The current ratecase settlement does not contemplate the current 5-year extension, although any potential reopening to amend treatment of deferred taxes would affect only the 60% subject to Californian regulation.
- **Cost of Capital: We could see an April 2017 ROE ratecase filing after a long hiatus.** The case would impact all three IOUs: SRE, EIX, and PCG. Following two extensions of the cost-of-capital (ROE) case for three

California investor-owned utilities off the initial 3-year decision, we suspect there could well be a case filed this Fall. We note specifically the cost of capital extension for 2016 suspended the banding mechanism for the ROE, seemingly reflecting consumer concerns that a rising interest rate environment could well push the ROE to the upper end of the band. While we believe the +/- 1% banding structure will remain in place tied to the Moody's Baa Utility index, we think the baseline of this ROE could indeed see some (modest) downward pressure under any formal review. We also note that the California Public Utilities Commission Office of Ratepayer Advocates recently expressed some anxiety over the current freeze of the Treasury rate banding mechanism (i.e., anxiety over the possibility of rising interest rates).

## **Aliso Canyon leak estimated at \$330M, offset by insurance; excludes penalties**

With the leaking natural gas storage well sealed on Feb 18<sup>th</sup>, the company now estimates "total costs for certain amounts paid and forecasted to be paid" at \$330M (90% from relocation and efforts to stop the leak with 10% from the cost of gas), with management concluding that \$325M of insurance recovery is probable (less retentions). This estimate excludes any damage awards, fines, or penalties, and any associated legal costs as a result of ongoing investigations commissioned by the California Division of Oil, Gas and Geothermal Resources (DOGGR) and the Public Utilities Commission (CPUC).

**SRE's insurance policies have a combined limit in excess of \$1B and management believes that these policies will cover costs associated with litigation and claims by nearby residents and businesses and some fines and penalties.**

For now, the company reports having about 15 bcf of gas remaining in the field and that the field is stable. SRE's insurance policies have a combined limit in excess of \$1B and management believes that these policies will cover costs associated with litigation and claims by nearby residents and businesses and some fines and penalties depending upon their nature and manner of assessment. For more on California see [Arguing the Case for California](#).

- **SoCalGas aiming to bring the site back into service by late-Summer.** The now-sealed well is one of more than 100 wells at the Aliso Canyon storage facility and that the leak is not affecting the utility's ability to serve customers with winter natural gas, although there is some concern at the California Independent System Operator (CAISO) over possible electric disruptions this Summer. SRE also has at least four types of insurance policies totaling in excess of \$1B of coverage that management believes will cover most claims (minus a modest "immaterial" deductible). Currently, multiple class action complaints for negligence, nuisance and trespass, and other things have been filed along with a suit from the Los Angeles City Attorney. While SRE has been working closely with various regulatory agencies, it may still face fines and penalties, although we note that so far, secondary damages appear to be limited. Management does not believe it is possible to accurately measure the amount of leaking gas and that speculation in the media is premature.
- **On March 17, regulators ordered SoCalGas to begin memo account tracking** of authorized revenues for Aliso Canyon in current and future rates. The CPUC will determine later whether some or all of the tracked revenues should be refunded to customers.
- **As a reminder, [SRE is awaiting approval by Jan 2016 for ratecase settlements](#) reached in September** for all its utilities that would grant 3.5% attrition increases for 2017 and 2018, which should allow for higher than 11%

EPS CAGR from 2015 through 2019 if approved. While some media reports have cited plaintiff allegations that the utility failed to comply with requirements for blowout preventer devices, the company reports that it has been in full compliance, with a surface preventer installed and operable, but evidently ineffective in the current incident. Furthermore, while there had been discussion within 1970's-era ratecase dockets of the possibility of installing subsurface preventers, these suggestions were ultimately rejected by regulators as likely ineffective and no such requirement for subsurface preventers has ever existed. We also note that no such equipment has ever been proposed as part of a funding provision for a gas storage integrity management program within the recent ratecase settlement (related to the state's post-San Bruno emphasis on gas safety).

- The leak was first detected by utility crews on Oct 23<sup>rd</sup>, and was sealed after a prolonged process of drilling an 8000-ft relief well to pump fluids and cement into the bottom of the storage cavern to permanently seal it. SDG&E offered temporary relocation to nearby homes affected by the smell of mercaptan in the leaking gas, although L.A. County officials confirmed by a directive order that none of the components of the leaking gas were being emitted at levels that would result in long-term health risks.

### **Will SRE successfully execute Mexican pipeline development and LNG export contracts?**

Although competition for pipeline contracts in Mexico has been surprisingly fierce, we do expect SRE's Ilenova subsidiary to continue to win a material proportion of over \$11B remaining opportunities through 2018, all of which would be upside to management's 11% projected base growth CAGR.

#### **Mexican pipeline bids under pressure**

SRE's Mexican subsidiary Ilenova recently lost a bid for the \$1B La Laguna – Aguascalientes pipeline contract. As reported in Bloomberg News on 3/7, Fermaca Infrastructure B.V. had bid below both TransCanada and Ilenova for the project. While not the sole factor used to determine a winner, we note that competition for infrastructure project development being auctioned by Mexico's Comisión Federal de Electricidad (CFE) has been very tough. We now await announcement of the winner for two other projects (Ville de Reyes – Guadalajara for \$555M and Tula – Villa de Reyes for \$420M) through April. A total of \$11B remains at stake by competitive bid through 2018.

**Something more structural?** We note this is the *second* project in the current procurement effort that management has failed to win; there is still a third key project contemplated in the near-term. We understand SRE will be keenly focused on winning this project, particularly after the technical disqualification from the last two projects. Management believes if it is to lose, it should be on price – and not technicalities around its bids.

**Figure 214: CFE Pipeline Bid Opportunities**

Development Opportunities	Capex (\$Mn)	Status	CODe
La Laguna – Aguascalientes	\$1,000	Bid in Feb, Award in Mar	2017
Ville de Reyes – Guadalajara	555	Bid in Feb, Award TBD	2017
Tula – Villa de Reyes	420	Bid in Mar, Award TBD	2017
Baja Sur	600	Bid in 2Q16, Award in 3Q16	2017
Texas – Tuxpan	3,100	Bid in 2Q16, Award TBD	2018
Nueces – Brownsville (U.S.)	1,550	Bid in 2Q16, Award TBD	2018
Mérida – Cancún	250	TBD	2016
Jaltipán – Salina Cruz (Pemex)	643	TBD	2017
Ramones - Cempoala (Pemex)	1,980	TBD	
Lázaro Cárdenas – Acapulco	456	TBD	2018
Salina Cruz – Tapachula (Pemex)	442	TBD	2018
<b>Total opportunities</b>	<b>\$10,996</b>		

Source: Company Filings

**Emphasizing all aspects of Mexico:** Mgmt is highlighting investment opportunities *beyond* just midstream as we see this segment becoming increasingly competitive. We note management continues to actively discuss future growth options before it. We emphasize that expectations remain diverse

- **Electric transmission:** Mgmt is also keen to take part in the future procurement of transmission, with RFPs beginning as soon as this Spring.
- **Getting rid of the last piece of merchant exposure:** mgmt is poised to sell within the next year its last remaining merchant generation plant, TDM in Mexicali. The plant is currently selling into the California market – and appears to be generating negligible earnings or EBITDA as best we can tell given the ~\$0.05 negative headwind. We're not surprised as such by the decision to sell the plant given this limited EPS profile (with the stock trading on P/E). The principle valuation question will be driven by expectations on the ability to interconnect into the Mexican grid – and receive contracts from the CFE among other potential buyers (industrials?). We suspect the 625 MW CCGT is worth ~\$75-200 Mn, entirely dependent on its prospects to contract in Mexico. We note the company itself has been trying to contract in the country unsuccessfully for some time already. The plant could be worth \$100-150/kW without success to sell into Mexico (~\$60-100 Mn.)

#### **FERC Environmental Assessment for Cameron Train 4**

SRE received the EA on Feb 12, 2016. This follows EPC contractor pricing for Train 4 received in October. As expected, the cost for Train 4 is lower than the costs per Train for Trains 1-3 due to the absence of expensive work environmental assessments work that was already done during the pre-filing period for Trains 1-3.

#### **Executed a Joint Development Agreement with Woodside Petroleum for Port Arthur on Feb 25**

Additionally, SRE has received its DOE FTA authorization for its Port Arthur projects. Port Arthur will need a full EIS from scratch, with the FERC filing definitely awaiting this. In any event, the most expensive part of the FERC process is the Front End Engineering Design (FEED) study, which we don't expect to be initiated until customer commitments are firmed up.

## Skipping MOUs for Cameron and moving directly to contracts in 2H16.

We see extra confidence for Cameron 4.

With the FERC filing in place and firm price quotes from EPC contractors received at the end of September, the company noted that moving directly to contracting is both the preference of potential customers as well as the company, and we see extra confidence for the project once 20-year full purchase and sales agreements are in place. However, with the contracts more detailed than a Memorandum of Understanding, the timeline for announcing customer commitments has been pushed out a bit to 2H16 vs 1H for the MOUs). Management's intention to reach Train 4 Final Investment Decision (FID) after contracting remains unchanged.

- Overall, it's unclear what the impact of lower oil prices has done to reduce desire to Train 4 of Cameron given discussions previously with integrated oil companies for offtake. In contrast, Port Arthur remains more of a utility-offtake project given its longer in-service cycle.
- Mgmt. agrees that LNG market is oversupplied till 2018, but believes additional capacity will be needed going into 2020 and beyond. Specifically, SRE has signed 27 LNG contracts in 2015, out of which 17 were 20- year contracts, 4 were 10-year contracts and rests were short term in nature.

Figure 215: Cost comparison of LNG Trains, UBSe

Trains 1 - 3		
Capacity	13.5 MTPA	14.95 Max
Cost	10 \$ bn	
Cost/Ton	0.74 \$/ton	
Trains 4 - 5		
Capacity	9.2 MTPA	9.97 Max
Cost	5 bn	
	20% Discount to original Train	
Cost/ton	0.59 \$/ton	Less than 1-3

Source: Company filings and UBSe

Figure 216: Quantity and Type of LNG contracts signed in 2015

Total number of C	27
20-year Contract	17
10-year Contract	4
Short-term Contra	6

Source: Company filings and UBSe

**Shareholders of IEnova voted on Sept 14th to approve an equity sale** for the pending acquisition of the other 50% of the **Pemex JV**. The transaction is expected to close in 3Q16; *while less than the initial accretion contemplated for 2016, SRE expects the deal to add ~\$0.02-\$0.05 to 2016 and ~\$0.10 from 2019 onwards (not yet in our EPS)*. IEnova will pay \$1.325B for Pemex's equity and assume debt of \$170M. Management intends to offset some of the expected dilution to its ownership of ~84% of IEnova through the application of about two years of IEnova dividends (~\$275M-\$325M) toward an investment in the deal. The decision to raise equity for IEnova is becoming increasingly important given its existing high leverage and ability to maintain its current AAA rating, as well as continued bidding in highly competitive Mexican natural gas pipelines sector. Question remains of timing for IEnova to go into the market with new equity offerings, given the recent slide in its shares and volatility in the Mexican market.

- Mexican regulators requiring competitive bids for assets but SRE still has right of first refusal.** As a result of the transaction, IEnova expects to own 100% of six purchased assets, five of which are currently in operation and are covered by long-term dollar-based contracts. IEnova and PEMEX will continue a 50/50 JV for the continued joint development of the Los Ramones Norte pipeline and other future infrastructure projects. ([See our LatAm utilities team's full report on IEnova](#)). An interesting distinction to be made for these assets is that they are more open access rather than marketed solely to the

original customer that sponsored its construction, which we believe should allow SRE greater latitude to optimize them and market any extra capacity arising from that process.

- **Keeping money in Mexico:** Additionally, for 2015 and 2016, instead of repatriating dividends associated with its investment in Mexico, SRE is planning to plough dividends back to IEnova, which is around half of \$300-\$325M per year total international dividend from Mexico. In total, SRE would contribute \$325 Mn to the total equity raise. We note that SRE recognized \$25M or \$0.10/sh of lower tax expense associated with the lower repatriation from Mexico in 3Q15. We believe the re-investment will offset some of the equity dilution of SRE in IEnova related to the investment in Pemex JV.
- **Dividends back to the US:** another headwind to the 11% growth rate? Among the latest updates to the story is the bonus depreciation extension and potential for management to extend international distributions while benefitting from its tax shield (on a cash basis). However, this would also increase the stated (book) income tax rate – and has a marginally negative impact on the overall growth rate. This remains somewhat of a wildcard for 2020 earnings, depending on the future pace of international distributions.
- **Is there a Mexican Energy FIBRA ("REIT") angle?** We note late last year new rules were approved in Mexico that would open up the FIBRA (equivalent to a US REIT structure) to the energy sector. We understand management continues to evaluate such a conversion. While a potential upside to shares of IENOV, we would not expect the tax benefits to accrue to SRE given the tax position. Irrespectively, we would expect IENOV subsidiary shares to react well.

**SRE remains somewhat exposed to lower natural gas prices** by about \$13M of net income for every \$1 move in gas pricing. Most of that exposure is from contracts at the ECA facility within the US Power and Gas segment. We see management as gradually reducing all remaining commodity volatility from its story.

## What else to consider into the Analyst Day?

- **Extension of Bonus Depreciation** should enable continued distributions to the US from foreign subsidiaries. This will increase the I/S effective tax rate. This is a modest headwind, albeit a cash flow benefit. Original disclosures had suggested this would end in ~2018.
- **Sale of TDM** – this project will be removed from forward expectations. Generating more cash at the IENOV subsidiary places more need to invest. The question of how the IENOV transaction will be restructured with Pemex given auction requirements is also key, but likely modest shift.
- **Renewables** has remained a modest piece of the business overall; we suspect this could shift modestly towards more involvement for SRE yet again as 'other' projects outside of simply midstream and LNG are evaluated. We see risk to mgmt putting too much in its midstream efforts given risk around execution at Cameron 4.
  - Shift towards renewables and electric transmission at IENOV remains a further incremental shift.

- **Utility operations** remain largely intact despite Aliso – and rather could see expedited spend. Rather, the risk is unrecoverable items, akin to the cycle PG&E has seen. We doubt investment will reach this level. We see analogies to BP Oil Spill, etc as exaggerating the scale of the current issues in SoCal; we see this rhetoric as more indicative of the concerning backdrop of attitudes around gas.
  - One possible impact on storage will be to create a stronger push towards electric storage and reduction on gas overall. This could yet be an opportunity for SDG&E, which already has the highest level of electric vehicle penetration.
- **M&A not off the table, but we see the focus on midstream.** With SRE unlikely to match large-cap peers in chasing material premiums for peer mid-cap utilities, we suspect the real opportunity lies around distressed midstream assets seeing utilities as having substantially better cost of capital access of late than MLP peers. Management is clear in being open to deals per past statements.
- **SB 350 passed last summer, raising California's renewable portfolio standard to 50% by 2030.** The California Energy Commission (CEC) notes that the recent cost of renewables – even without tax subsidies – is approaching levels competitive with natural gas. [The CEC recommends](#) a "new procurement requirement to increase renewables beyond 33%, including allowing for rooftop solar and better coordination with Western states and Baja California to maximize renewable energy production and better balance production with demand."
- **Will renewables be a source of growth?** Management continues to pursue select projects and we look for expanded renewable investments as management seeks the next 'wave' of long-term investments to keep its trajectory ongoing.
- We note that S&P moved up SRE's **credit rating to a stronger business risk** profile and Moody's continues to target a minimum 17% FFO/Debt metric vs our projection (and management's) for the low 20's% once Cameron Trains 1-3 come online. We see significant flexibility here, especially with the expected \$440M of proceeds from the sale of SRE's 25% interest in the Rockies Express Pipeline (REX) in 2016.

**Figure 217: SRE Cash Flow and Credit Metrics: Lots of Latitude**

Projected Credit Metric Analysis (Moody's)	2013	2014	2015	2016E	2017E	2018E	2019E	2020E
Cash Flow From Operations	\$1,784	\$2,161	\$2,905	\$4,084	\$3,098	\$3,629	\$3,779	\$3,758
- Changes in Working Capital	\$421	\$375	(\$699)	(\$690)	(\$93)	(\$242)	(\$245)	(\$94)
- Changes in Short Term Op. Assets & Liabs.	<u>\$200</u>							
<b>FFO (CFO pre-W/C)</b>	<b>\$2,405</b>	<b>\$2,536</b>	<b>\$2,206</b>	<b>\$3,394</b>	<b>\$3,004</b>	<b>\$3,387</b>	<b>\$3,534</b>	<b>\$3,664</b>
+ Long-term Debt - Gross	\$12,945	\$14,369	\$15,473	\$15,632	\$15,884	\$15,689	\$15,523	\$15,446
Pensions Expense	24	24	24	24	24	24	24	24
Operating Lease Expense	54	54	54	54	54	54	54	54
Capitalized Interest	-44	-44	-44	-44	-44	-44	-44	-44
Debt Additions								
Pension	670	670	670	670	670	670	670	670
<u>Capitalizing Operating Lease</u>	<u>741</u>	<u>714</u>	<u>687</u>	<u>660</u>	<u>633</u>	<u>606</u>	<u>579</u>	<u>552</u>
Additions to Debt	1,411	1,384	1,357	1,330	1,303	1,276	1,249	1,222
Adjusted Debt Balance	14,356	15,753	16,830	16,962	17,187	16,965	16,772	16,668
Adjusted FFO	<u>2,439</u>	<u>2,570</u>	<u>2,240</u>	<u>3,428</u>	<u>3,038</u>	<u>3,421</u>	<u>3,568</u>	<u>3,698</u>
<b>Adjusted FFO/Debt Metric</b>	<b>16.99%</b>	<b>16.31%</b>	<b>13.31%</b>	<b>20.21%</b>	<b>17.68%</b>	<b>20.17%</b>	<b>21.28%</b>	<b>22.19%</b>
<i>High Teens Target for Moody's (min would be 17%)</i>								

Source: UBS Estimates, Moody's, Company filings

## Deploying the Balance sheet: How much latitude?

We estimate North of \$2 in EPS potential growth in 2020+ with full deployment of the balance sheet to just the Moodys targets. Moreover, we see potential for greater latitude to exist with Moodys as the present growth strategy is executed, more consistent with S&P min of 13%. We emphasize the near-term metrics are tighter due to the LNG construction cycle but project substantial improvement.

**Figure 218: Balance Sheet Redeployment – EPS uplift potential**

<b>Part 1:</b>	
2020e FFO/Debt	22.19%
Min FFO/Debt	17%
Leverage Capacity	5%
Incremental Leverage (\$ Mn)	5,085
EV Assuming 50/50	10,169
<b>EPS Uplift @ ROE ~10%</b>	<b>2.02</b>
<b>Part 2:</b>	
Additional ~\$700 Mn Equity from REX & LDC	
<b>EPS Uplift @ ROE ~10%</b>	<b>0.28</b>

Source: UBS estimates

## Valuation: Maintain \$116 PT

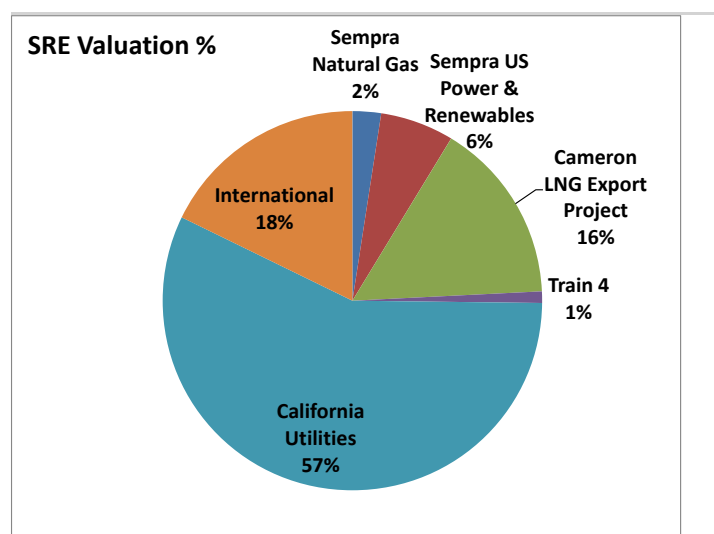
We continue to value SRE on a 2018E-based SOTP basis and summarize the components below.

Figure 219: Summary Sempra Sum of the Parts Analysis

Summary Sempra Sum of the Parts Analysis - UBSe		
Segment	Primary Methodology	Valuation/Share
<b>Sempra Natural Gas</b>		
Storage, Cameron (Import & Interstate), and REX	7-12x EV / EBITDA	\$2.22
Gas LDCs	18x P/E	\$0.98
<b>Total Sempra Natural Gas</b>		<b>\$3.20</b>
<b>Sempra US Power &amp; Renewables</b>		
Solar	14.5x EV/EBITDA	\$3.23
Wind	8-15x EV/EBITDA	\$0.49
Accelerated Depreciation Tax Shield and Other	NPV	\$4.51
<b>Total Sempra US Power &amp; Renewables</b>		<b>\$8.23</b>
<b>Cameron LNG Export Project</b>		
Trains 1-3	NPV of 10x EV /	\$20.38
Accretion due to GP/LP Structure in MLP	EBITDA	\$0.00
Train 4	discounted to 2018	\$1.31
<b>Total Cameron LNG Export Project</b>		<b>\$21.69</b>
<b>California Utilities</b>		
SoCal Gas	19x P/E (No discount)	\$33.15
SDG&E	18x P/E (No discount)	\$41.80
<b>Total California Utilities</b>		<b>\$74.95</b>
<b>International</b>		
SRE Mexico/IE Nova	Public Value	\$15.26
Chile (Chilquita) - Unlisted	10x P/E	\$4.03
Peru - Listed	Public Value	\$4.06
<b>Total International</b>		<b>\$23.35</b>
Less: Parent Debt	Book Value	(\$15.54)
<b>Grand Total Sempra</b>		<b>\$116.00</b>

Source: UBS Estimates

Figure 220: UBSe Valuation for SRE, % of Price Target



Source: UBS Estimates

## Southern Company

*Southern has underperformed YTD with a sharp decline following the 4Q15 update with guidance revisions that missed expectations but shares have largely tracked the market since that point. The latest Kemper update shows that there is still a fair amount of work to be done with risk around the in-service date. Vogtle costs increased (as expected based on the contractor settlement) but construction appears to be on track. The AGL merger also made notable progress during the quarter. In sum, developments have been mixed but we continue to see a negative risk/reward skew at this level.*

We forecast SO reporting adjusted 1Q16 EPS of **\$0.53** in-line with consensus/Guidance with rate relief in Mississippi and Georgia compensating for a challenging weather comparison. As discussed with many other companies in the report the combination of favorable weather in 1Q15 and below-average HDDs in 1Q16 depresses expectations. As a result we look for O&M growth to be on the lower-side as management looks for an offset. We remain cautious on industrial sales activity in the southern portion of the US following datapoints of challenged US exports and will focus on management commentary for updates. Southern Power continues to be a bright spot for the company and should approximately offset depreciation, including the impact of acceleration depreciation.

Although weather creates a difficult comparison the rate relief in Mississippi helps to mitigate the magnitude of the decline. There is some leeway in the O&M plan such that spending can be shifted to compensate for the impact of weather, thereby helping management to achieve its guidance

Figure 221: SO 1Q16E Earnings Walk

Southern Company 1Q16 Earnings Walk		EPS
<b>1Q15A Adjusted EPS</b>		<b>\$0.56</b>
Weather vs Normal in 1Q15		(\$0.04)
Weather vs Normal in 1Q16		(\$0.03)
Economic Growth (Industrial Sales)		\$0.01
Wholesale Ops		\$0.00
Rate Relief		
GA: Base Rate Step-Up Jan 2016		\$0.01
GA: Nuclear Cost Recovery Tariff		\$0.00
MS Power: Rate increase Jan 2016		\$0.03
MS Power: Performance Evaluation Plan		\$0.00
MS Power: AFUDC on Kemper		\$0.00
Gulf Power: Capacity and Environ.		\$0.01
Alabama Power: Rate Stabilization		\$0.00
Southern Power		\$0.02
Interest Expense		(\$0.00)
Non-fuel O&M: 3.0-3.5% YoY Increase		(\$0.02)
Other income and deductions		\$0.00
D&A		(\$0.02)
Share Dilution		(\$0.00)
<b>1Q16E Adjusted EPS</b>		<b>\$0.53</b>
1Q16 Guidance		\$0.53
1Q16 Consensus		\$0.53
2016 UBSe EPS		\$2.83
2016 Consensus		\$2.85
2016 Guidance		\$2.76-\$2.88

Source: Company filings, FactSet, UBS estimates

*For additional context, please refer links to relevant recent reports below:*

[2/5/16 More Cash But a Lower Profile](#)

[11/3/15 Focus on Mississippi Elections](#)

[8/26/15 Doubling Down on Atlanta](#)

[7/30/15 August Calendar Heating Up](#)

[7/10/15 Getting Messy in Mississippi](#)

[4/30/15 Holding Our Breaths for a Deal](#)

[2/5/15 Still Struggling](#)

## What are the pivotal questions for SO?


### What is the latest status for the Kemper construction and recovery?

- **Kemper costs tick higher once again with latest delays:** On April 1<sup>st</sup> Southern Company (SO) filed its latest Plant Ratcliffe (Kemper County) Integrated Coal Gasification Combined Cycle (IGCC) monthly report which included a relatively small cost increase but longer schedule delays than in the previous report. The disclosed \$18Mn cost increase was comprised primarily of EPC (\$21Mn) and pre-construction operations (\$35Mn), offset by a \$35Mn 'schedule risk' release. Previously Southern estimated the damages to the refractory lining as a ~\$10Mn item.

SO is working on repairs for train A and inspecting B

Repairs and modifications to the gasifier refractory lining continue, and management also cites ongoing start-up and commissioning challenges

**Figure 222: Kemper IGCC Monthly Status Reports: Milestone Delays**

Kemper IGCC Monthly Status Reports 		
Key 90-Day Milestones	Dec 2015 Report	Feb 2016 Report
LDF Non-Dome	February 2016	April 2016
Lignite Dryers Ready for First Lignite Feed	February 2016	May 2016
AGR Commissioning - Train A	April 2016	May 2016
Refractory Cure - A	April 2016	July 2016
First Lignite Feed - A	April 2016	July 2016
First Syngas Production - A	April 2016	July 2016
Reliable/Clean Syngas Available - A	N/A	July 2016

Source: Company filings, MPSC Docket 2009-UA-0014

The repairs for the refractory have caused multiple key milestone delays to slip as well. For example the first lignite feeding and syngas production for train A have not been delayed to July from April indicating that the latest refractory issues seem to have caused an approximate three-month delay. In the previous Kemper IGCC report through December 2015 the activities for train A were delayed from February/March to April; the greater delay in the latest report could indicate that the issues identified were more significant than originally thought. Although train A has faced issues, we understand that train B's timeline is still consistent with the previous filing. The next report is expected to be filed in late April, likely ahead of Southern's earnings call on April 27<sup>th</sup> based on the historical pattern.

Recall that SO previously announced further delays to the target in-service date to August 31, 2016 (from June 30) for the Kemper IGCC plant with an additional \$110M of unrecoverable costs. Delays beyond August 31<sup>st</sup> are expected to incur ~\$25-\$35Mn monthly 'base costs' (subject to the cost cap) and ~\$15Mn expenses not subject to the cost cap. (Docket 2015-UN-0080)

Permanent rates are now in place for the combined cycle which is in-service and SO plans to file the next ratecase when the balance of the plan is in-service. The magnitude of the rate increase will depend on how much tax relief is received from the IRS

As of mid-April 2016 Southern was hiring a gasification technician for Kemper

- **Separately Southern still sees the opportunity for favorable tax outcomes related to Kemper:** Southern is in ongoing discussions with the IRS about whether the cost of the Kemper IGCC plant would qualify for the Section 174 Research and Experimentation (R&E) tax deduction. Mississippi Power can recognize the tax deductions as dollars are spent on eligible investments and the company has so far taken \$3Bn of deductions with a \$1Bn reserve. While uncertain, management indicated that this could more than offset the loss of the Phase II credits and would not require the same 'strict standards' about the operations of the carbon capture system as the Phase II credit. If unsuccessful in this deduction SO believes bonus depreciation is a decent 'hedge' that allows the ability to deduct a material portion of the plant.

R&E deduction could be significantly larger than the Phase II credits

Also included in the tax extenders bill is the opportunity for reallocation of the US Department of Energy's \$160Mn grants from the Clean Coal Power Initiative (CCPI) that were previously allocated to projects that were ultimately not completed. A primary beneficiary of this provision could be Kemper, with Mississippi Public Service Commissioner Brandon Presley commenting that **\$80-\$100Mn** could be allocated towards Mississippi Power ratepayers. SO has pointed towards the lower-end of the range simply assuming that the \$160Mn of available funds could be split evenly between Kemper and another eligible project.

Release of additional 'Clean Coal' funds could be worth \$80-\$100Mn but has not been finalized yet

With the remaining ratecase to be filed once the plant is in service, we note the more favorable composition of the Miss Public Service Commission (PSC) since last year's election that defeated anti-Kemper advocate Blanton. Management estimates that after a 15% rate increase in December (plus refund checks), another sizeable rate increase will be necessary once in-service, although this could be offset with tax credits and grants.

### What is the latest status for the Vogtle construction and recovery?

- **Latest report shows higher costs but stable timeline:** For the Vogtle new nuclear construction project, the Georgia Public Service Commission (PSC) ordered a review of the recent Vogtle agreement which could result in a settlement to declare costs incurred and the future estimates as prudent. On April 5<sup>th</sup> Georgia Power submitted a Supplemental Information Report (SIR) for Vogtle arguing that all costs incurred for the projects through the April 5<sup>th</sup> filing were prudent and that management believes the forecasted costs are "reasonable". Although Georgia Power's share of the total project costs have increased to \$5.44Bn from \$4.42Bn originally, going forward SO estimates that the total rate increase for Vogtle will be 6-7% with ~4.5% already included in rates versus up to 12% excluding CWIP originally forecasted.

Management commented that construction has been going very well at the plant with mild weather helping

In the SIR and the Vogtle Construction Monitoring (VCM) report 14 Southern shows that the bulk of the cost increases relate to "quality assurance, compliance, and operations & EPC scope changes. Southern requests approval of \$160Mn of 2H16 expenses in the report with unchanged target COD for units 3 (June 2019) and 4 (June 2020) but Southern increased its estimate for its share of the costs by \$395Mn due primarily to the EPC settlement.

It remains to be seen how the Commission will treat and rule on the Westinghouse settlement

The Georgia PSC approved Southern's full \$148Mn request on February 19 for the VCM 13 report covering 1H15 expenses. Importantly VCM 13 did not include a change in the schedule of costs for the construction of the plant. (Docket 29849)

**Figure 223: Capital Forecast at Georgia Power Company Ownership Percentage (\$Mn)**

Capital Forecast at Georgia Power Company Ownership Percentage (\$Mn)			
<b>Original Capital Forecast</b>			<b>\$4,418</b>
Changes through VCM 13		627	(A)+(B)
<b>Currently Field Capital Forecast</b>			<b>\$5,045</b>
Proposed VCM 14 Changes: EPC Scope Change			
Settlement		326	
Cyber Security		46	
Resolution of Open Notices of Change		23	
<b>Total Proposed Changes for VCM 14 with Settlement</b>			<b>395 (C)</b>
<b>Capital Forecast Proposed for VCM 14</b>			<b>\$5,440</b>

Change Including Escalation			
Capital Cost Category (\$Mn)	VCM 1-8	VCM 12	VCM 14
Power Block and Support Structure			
Construction	\$24	\$17	\$0
Federal Regulation Changes	32	25	21
Settlement	0	0	350
Taxes and Fees	50	53	0
Operational Readiness	91	48	24
Owners Quality and Compliance	152	75	0
Legal/Environmental Permit/Misc.	12	29	0
Transmission	19	0	0
<b>Total Changes from Original Certification</b>	<b>\$380 (A)</b>	<b>\$247 (B)</b>	<b>\$395 (C)</b>

Source: Company filings

### What is the status of pending M&A?

- **AGL merger clears key hurdle in Georgia:** Southern Company and AGL Resources cleared another hurdle in their Georgia-jurisdictional merger proceedings last week when the Georgia PSC unanimously approved the settlement. We continue to expect the companies will receive approval in the other jurisdictions. Below is a table that summarizes key milestones and upcoming events:

**Figure 224: Key Merger Milestones as of April 15<sup>th</sup>**

State	Key Milestones
GA	4/4/16: Reached settlement agreement; 4/14/16: Commission unanimously approves merger
IL	10/8/15: Filed merger approval application; 4/20-4/21/16: Evidentiary hearings
MD	11/3/15: Filed merger approval application; 3/31/16: Maryland Commission issued proposed order approving settlement; awaiting final approval
NJ	10/16/15: Filed merger approval application; 5/17-5/20/16: Evidentiary hearings
VA	10/26/15: Filed merger approval application; 2/23/16: Stipulation approved
CA	11/9/15: Filed merger approval application; 3/22/16: Approval received

Source: Company filings

- **Financing:** \$1Bn of equity is expected to be issued in the near-term (1Q15-2Q15) with \$7Bn of debt close to the transaction closing which is scheduled for 2H16.

- **Synergy information not expected:** While synergies are expected to some extent, SO has not disclosed specifics and continues to emphasize that cost savings were not a strategic driver of the deal. Southern management has commented that AGL is already highly efficient due to its historical mergers so has not touted significant synergies. As part of the Georgia settlement SO will retain any merger cost savings through YE19, retain 40% of the savings from 2020-2022, and the customers will receive the benefit from any synergies beyond that point.

We assume that cost savings can be achieved at the corporate level but as typical for merger processes we do not expect details until close. The synergies that may result from having SO and AGL's headquarters in GA has the potential to drive EPS growth

- **PowerSecure deal announced in Feb expected to close by the end of 2Q16:** Southern announced the \$431Mn (\$18.75/share) PowerSecure (POWR) transaction on February 24<sup>th</sup> and the strategic rationale according to management is to rapidly develop a "behind the meter" services business. Target customers include large commercial, industrial, and government (especially DoD) entities with a need for reliable on-site backup and primary power, such as data centers, hospitals, grocery storage and retail, etc. The business is virtually 100% fee-based, with SO intending to focus on expanding the customer base and extending contract lengths from the current 18 months. The PowerSecure shareholder vote is scheduled for May 5<sup>th</sup> which follows the termination of the HSR waiting period on March 31<sup>st</sup>.

Assuming the transaction closes, PowerSecure will sit under the corporate parent and be separate from Southern Power

It was recently reported that Georgia Power cancelled an \$85Mn solar contract with PowerSecure but Southern management reported that this was purely a specific business decision and not reflective of the broader relationship between the two parties. Southern expects to work with PowerSecure in the future.

#### How large could Southern Power capex get?

- **Southern Power is one of many potential buyers of SUNE assets:** Recent filings indicate Southern Renewable Energy is planning to acquire the 40MW Passadumkeag Mountain wind project in Penobscot, ME from Quantum Power (which owns ~70% of the project). SUNE had previously filed to buy the project in November 2015 but noted intent to cancel in late February. Passadumkeag has a 15-year contract in place with Eversource Energy for the majority of the capacity and energy, in addition to equivalent RECs.

Separately, SO closed on the 120MW East Pecos Solar project (Dec 2016 COD with a 15 year PPA at Austin Energy) on March 4 and 20MW Calipatria Solar (90% owned with 20-year PPA with SDG&E), bringing total renewable acquisitions in the quarter to ~140MW (not counting Passadumkeag which is pending).

## EPS Estimates

Below we present our EPS estimates which do not include any potential accretion from the pending AGL Resources acquisition but we show illustratively the estimated accretion. Further details on the accretion profile are available in our previous note [‘Doubling Down on Atlanta’](#).

Following Georgia’s approval of the AGL transaction we now include value for the subsidiary in our price target

Figure 225: Southern Company EPS Estimates

SO EPS Estimates	2014A	2015E	2016E	2017E	2018E	2019E
Alabama Pow er	\$0.85	\$0.88	\$0.86	\$0.87	\$0.95	\$1.00
Georgia Pow er	\$1.37	\$1.40	\$1.44	\$1.48	\$1.53	\$1.58
Gulf Pow er	\$0.16	\$0.16	\$0.19	\$0.19	\$0.19	\$0.20
Mississippi Pow er	\$0.25	\$0.25	\$0.27	\$0.28	\$0.30	\$0.34
Southern Pow er	\$0.19	\$0.24	\$0.24	\$0.20	\$0.16	\$0.10
Other	(\$0.01)	(\$0.04)	(\$0.18)	(\$0.17)	(\$0.16)	(\$0.15)
SO, UBS Estimates	\$2.80	\$2.89	\$2.83	\$2.85	\$2.97	\$3.07
		3.0%	-2.0%	0.8%	4.2%	3.3%
Guidance Range	\$2.76-\$2.88		\$2.76-\$2.88			
3-Yr EPS CAGR off 2016E Midpoint (\$2.82) without AGL						2.9%
Estimated Potential Accretion from AGL & Staggered Equity				\$0.12	\$0.07	\$0.07
3-Yr EPS CAGR off 2016E Midpoint (\$2.82) with AGL						3.7%
Prior UBSe			\$2.82	\$2.85	\$2.97	\$3.08
Standalone guidance midpt (adj for bonus and dilution)			\$2.82	\$2.83	\$2.93	\$3.03
Street Consensus			\$2.93	\$3.04	\$3.18	\$3.27

Source: Company filings, FactSet, UBS estimates

## Valuation: Increase price target \$3 to \$47

We are rolling forward our valuation to 2018E from 2017E previously continuing to use a sum-of-the-parts methodology. Although progress has been made on the large construction projects, we continue to apply significant discounts to the subsidiaries with elevated regulatory and execution risks (Vogle and Kemper). Following Georgia’s approval of the AGL transaction we now include value for the subsidiary in our price target. We detail out the changes to our valuation on the right with the most significant factor being the ~+1x improvement in the regulated peer multiple since our last mark-to-market.

What’s change in our valuation?  
 +\$3/sh Increase in Peer Multiple  
 -\$1/sh Rolling to 2018E  
 +\$1/sh AGL Accretion

Figure 226: Sum-of-the-Parts Valuation

Southern Company Valuation (UBSe)		Downside Case		Base Case		Upside Case	
Business Segment	2018E EPS	Valuation Multiple	Per Sh. Value	Prem/Discount	Valuation Multiple	Per Sh. Value	Valuation Multiple
<b>Regulated Business</b>							
Alabama Power	\$0.95	15.5x	\$14.73	0.00x	16.5x	\$15.68	17.5x
Georgia Power	\$1.53	14.0x	\$21.43	-1.50x	15.0x	\$22.96	16.0x
Gulf Power	\$0.19	15.5x	\$3.02	0.00x	16.5x	\$3.21	17.5x
Mississippi Power	\$0.30	13.0x	\$3.92	-2.50x	14.0x	\$4.23	17.5x
Southern Power (Contracted Merchant)	\$0.16	14.5x	\$2.30	-1.00x	15.5x	\$2.46	16.5x
Other	(\$0.16)	15.5x	(\$2.53)	0.00x	16.5x	(\$2.69)	17.5x
Potential Accretion from AGL	\$0.07	14.5x	\$1.01	-1.00x	15.5x	\$1.08	17.5x
<b>Southern Company Total/Implied</b>	<b>\$3.04</b>	<b>14.5x</b>	<b>\$44.00</b>		<b>15.4x</b>	<b>\$47.00</b>	<b>16.8x</b>
Shares Outstanding (2018E Mn)				942	Overall discount		
Regulated Peer Group Multiple				16.5x	-6.4%		

Source: Company filings, FactSet, UBS estimates

# Talen Energy Corp.

Talen has been a top performer and the stock has nearly doubled in the past three months as media reports have indicated that TLN could be a target of a LBO. We believe a transaction is a credible possibility. We see any potential Talen transaction as following the continued trend of public-to-private through the latest downturn in Power & gas prices (already exhibited in recent weeks with the latest DYN-ECP deal).

We estimate Talen reporting 1Q16 adjusted EBITDA of **\$186Mn**, in-line with consensus but sharply lower YoY due primarily to continued margin erosion as hedges roll-off into a lower pricing environment. The combination of asset disposals and acquisitions should approximately net out. 1Q16 should have some impact from the lumpy Susquehanna outages as the 2016 outage began on March 12<sup>th</sup> while the 2015 outage started around April 10<sup>th</sup>.

Talen's 1Q performance appears in-line with consensus but we investors are focusing more on the prospects for M&A following media reports than the quarterly performance

Figure 227: TLN 1Q16E EBITDA Walk

Talen Energy 1Q16 EBITDA Walk	EBITDA
<b>1Q15A Adjusted EPS</b>	<b>310</b>
Asset Disposals	(\$48)
Asset Acquisitions	\$40
Margins	(\$101)
O&M and Other	(\$26)
Synergies	\$10
<b>1Q16E Adjusted EPS</b>	<b>186</b>
<b>1Q16 Consensus</b>	<b>188</b>
<b>2016 UBS<sub>e</sub> EPS</b>	<b>\$742</b>
<b>2016 Consensus</b>	<b>\$778</b>
<b>2016 Guidance</b>	<b>635-835</b>

Source: Company filings, ThomsonReuters, UBS estimates

*For additional context, please refer links to relevant recent reports below:*

[4/5/16 Many Options On The Table](#)

[3/9/16 A Call to Action](#)

[2/25/16 How Will Capital Be Allocated?](#)

[1/7/16 Will 2016 Offer a Turnaround?](#)

[11/16/15 Riding the Power Curve](#)

[10/26/15 Unpacking the Latest Portfolio Developments](#)

[10/9/15 Extracting Top Dollar on Divestments](#)

[9/18/15 Capacity Auction Misses The Mark](#)

[8/18/15 Tapping Into Gas Conversions](#)

[8/7/15 Traveling on Calmer Waters \(Upgrade to Neutral\)](#)

[7/21/15 Deploying The War Chest](#)

[7/20/15 Opening The War Chest?](#)

## What are the pivotal questions for TLN?

### How do the latest media reports influence the investment thesis?

- **Media report raises possibility of an LBO scenario:** On April 1<sup>st</sup> a Bloomberg article (sourced to Spark Spread) reported that Talen could be target of a potential Leveraged Buyout (LBO) offer from a variety of suitors including Blackstone and Riverstone. On April 15<sup>th</sup> a subsequent media article (DealReporter) cited that Talen has hired an advisor for “broad process” to consider a sale. We believe a transaction involving private equity is plausible for a variety of reasons:

1) **Riverstone owns 35% of TLN already** as part of the original spin-merge with PPL executed in June 2016.

2) Senior management including the CEO and CFO agreed to severance agreements in December/January. This reduces disincentives with a take-over offer.

3) There are **limited change of control provisions** on ~70% of TLN’s long-term debt. The \$600Mn 6.5% Talen Energy Supply notes and the \$231Mn of municipal debt have ‘double trigger’ change of control provisions. The Mach Gen non-recourse secured debt also has a change of control provision which would require a waiver from the creditor in a change of control scenario. We detail out the capital structure on the next page. Other provisions to be aware of include a 4.5x net debt/EBITDA limitation on the revolver and a fixed coverage ratio of 2:1 on the notes.

4) **Room for optimization in the capital structure** presents an opportunity as well. When we last met with management in March they stated that they were exploring adding secured asset-level debt to create further capacity to reduce corporate obligations. Management was carefully weighing its options as it sees value in its current flexible capital structure which does not have significant covenants currently. Either Talen or an acquirer could issue secured debt to paydown more expensive corporate debt trading at a discount.

5) **Private equity has pursued similar deals in the past.** We see the potential interest to buy the company for effectively ‘the cash on the balance sheet’ as analogous to prior Blackstone efforts to buy DYN in 2010. Similar to the Dynegy’s Engie joint venture recently, we believe a transaction between Talen and a private party would be perceived positively by the market and a positive for other IPPs seeing another private entity stepping into the energy fringe.

- **Regardless, we see credit leverage as a near-term datapoint:** Despite a challenging fundamental outlook for the merchant power business, we see management in a strong position to capture value through an exchange of its debt. We see leverage through both its cash position (~\$1.1Bn capital available for allocation ‘16E vs. ~\$1.5Bn market cap), as well as the Investment Grade covenant package associated with the original PPL Supply issuance. The IRR on repurchasing debt has declined significantly as the bonds have rallied on the media reports of an LBO. As we show in the charts below, the 2019 debt has jumped to 87 from 75 in February, reducing the value creation from repurchasing debt below par.

Talen has consistently stating it viewed itself as a platform for further acquisitions to gain scale and we see LBO as fitting into a similar logic

The potential for TLN to issue secured project level debt (senior in the capital structure) could make an exchange offer more credible

As part of the Engie transaction Energy Capital Partners (ECP) received common stock – this indicates to us that private investors are interested in IPPs at these price levels

## How a potential LBO shift the capital allocation plans?

- **Will TLN execute on a capital allocation plan or will it wait?** Previously management has said that it will provide an update on its capital allocation plans when it received the cash from the hydro asset sale (occurred on April 1<sup>st</sup>) and made a decision on the gas-firing addition to Montour (1H16) so the company should have visibility here. If the reports of a potential LBO are valid, we believe any acquirer would likely prefer transacting before Talen begins repurchasing debt to maximize the set of opportunities. For example, as mentioned Talen has indicated that it could pursue adding secured debt to assets to free-up capital for tender unsecured corporate debt. If this plan is executed with further restrictions placed on debt, it could create value for Talen today, but it could reduce flexibility in the capital structure. While a private equity player could buy the assets for the 'cash on the balance sheet', the reality is the investment to buy the company is a real one as the cash cannot be 'taken' from the company but rather deployed to fund further growth or debt restructuring avenues.

**Secured debt could help facilitate liabilities management program: Talen has been exploring whether it should add more secured asset-level debt to some of its facilities in order to create capacity to reduce corporate level obligations. Management is carefully weighing its options as it sees value in its current flexible capital structure which does not have significant covenants currently**

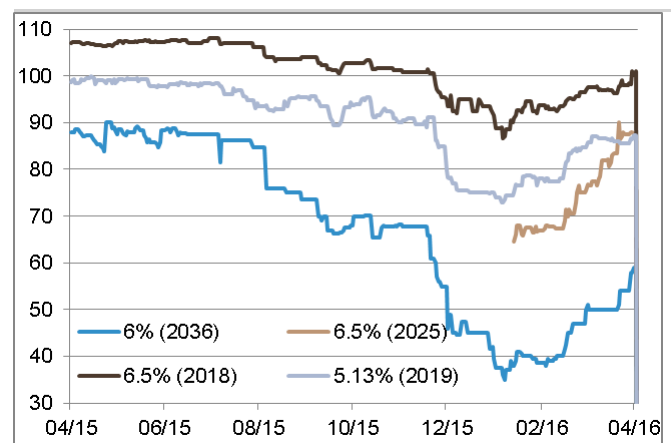
Below we detail estimated capital available for allocation showing that management still has adequate cash at its disposal to make a dent in upcoming maturities. Talen indicated that an update on capital allocation is unlikely until it has actually received the divestiture proceeds cash (occurred April 1<sup>st</sup>) and made a decision on the Montour gas project (1H16).

**Figure 228: Talen Cash Flow Analysis: How Much Liquidity?**

Cash Flow Analysis (\$Mn)	2016E
YE15 Unrestricted Cash Balance	141
Release of Restricted Cash	55
Divestiture Proceeds	1,220
2016E FCF	270
Less: TSA Costs	(25)
Less: Feb Revolver Repayment	(500)
Less: Jan Ironwood Redemption	(41)
<b>Capital Available for Allocation</b>	<b>1,120</b>
Less: 2016 Debt Maturities	(355)
Less: Minimum Cash Target	(200)
<b>Remaining Available for Allocation</b>	<b>565</b>
<b>Committed 2016 Debt Reduction</b>	<b>(896)</b>
<b>Total Potential Debt Reduction in 2016</b>	<b>(1,461)</b>

Source: Company filings, UBS estimates

**Figure 229: Talen Bond Trading Values**



Source: FactSet

If Talen had to reprice its debt today it could see \$45Mn of additional interest expense, while significant this is down from \$75Mn in February before the bonds rallied.

Figure 230: Talen Long-Term Debt as of 12/31/15

As of 12/31/15	Maturity (yr)	Book Yield	Current Yield	2016	2017	2018	2019	2020	2021+
<b>Talen Energy Supply, LLC</b>									
<b>Senior Notes:</b>									
Talen ES 5.70% (A)	2015	5.70%	N/A						
Talen ES 6.20%	2016	6.20%	6.18%	350					
Talen ES 6.50%	2018	6.50%	6.44%			400			
Talen ES 5.125%	2019	5.13%	5.87%				1,220		
Talen ES 4.60%	2021	4.60%	5.94%						712
Talen ES 6.50% (B)	2025	6.50%	7.54%						600
Talen ES 6.00%	2036	6.00%	10.17%						200
<b>Total Senior Notes</b>		<b>3,482</b>		350	-	400	1,220	-	1,512
<b>Municipal Bonds: (B)</b>									
Talen ES variable-rate Series A	2038	6.40%	6.40%						100
Talen ES variable-rate Series B	2038	3.00%	6.40%					50	
Talen ES variable-rate Series C	2037	6.00%	6.40%					81	
<b>Total Municipal Bonds</b>		<b>231</b>						131	100
<b>Talen Ironwood, LLC</b>									
Talen Ironwood (A)	2025	8.86%		41					
<b>MACH Gen LLC (GenCo)</b>									
Term Loan B (B)	2022	4.25%	5.87%	5	5	24	24	48	368
<b>Total Maturities</b>		<b>4,228</b>		<b>396</b>	<b>5</b>	<b>424</b>	<b>1,244</b>	<b>179</b>	<b>1,980</b>
Book Interest Expense (Consolidated)		\$223	Book Interest Expense (Ex-GenCo)		\$203				
MtM Interest Expense (Consolidated)		\$269	MtM Interest Expense (Ex-GenCo)		\$242				
Delta (%)		-17%	Delta (%)		-16%				
2018E EBITDA (UBSe)		\$599	2018E EBITDA (UBSe)		\$487				
Delta (%)		-8%	Delta (%)		-8%				
2018E FCF (UBSe)		\$103	2018E FCF (UBSe)		\$72				
Delta (%)		-45%	Delta (%)		-54%				

Note: Current Yield as of April 15, 2016.

Source: Company filings, FactSet, UBS estimates

### What is the outlook for the non-core assets?

- **Steadily making progress on Colstrip but no firm answers yet:**  
Washington State Governor Jay Inslee recently signed a Senate Bill that allows Puget Sound Energy (PSE) to create a fund that would cover the decommissioning costs at the coal-fired Colstrip plant in Montana which is jointly owned with Talen. PSE estimated the costs to decommission units 1 & 2 at approximately \$130-200Mn. The Gov. stated the bill takes an important step towards reducing the state's reliance on coal, while incentivizing a transition to clean energy. TLN and PSE both stated they were willing to participate in exploring alternative ownership arrangements.
- **Best Harquahala risk/reward likely involves finding a local solution:**  
Management believes the best risk/reward is in finding a local solution such as selling the plant to a local utility or entering into a PPA rather than attempting to move the unit. While the cost estimate to relocate the asset has been refined to ~\$315-\$500/kW, if management is able to realize \$500-\$700/kW in value depending on the market for the new plant it would have essentially the same value creation as if it simply sold the asset for ~\$200-\$250/kW without the risk of transportation.

**Divesting Colstrip could create tax savings**

**We're biased to believe the asset is able to get a contract – rather than moving**

**Management has indicated it would address the future of this plant in 2016E**

As a reminder, Arizona Public Service has an RFP which began in March but the timeline could be protracted – [details on the RFP are available in our Conference note here \(Page 45\)](#).

The plant was built in a modular way, has three independent units, and TLN has been working with firms that specialize in the type of work so management is not concerned by the prospects of moving the asset; however, we would be surprised if management opts to relocate the asset. In the interim Talen is attempting to improve the cost structure of the plant and reduce the EBITDA drag which is estimated to be \$5-10Mn.

It would appear the cost of transporting the plant could approach ~\$350/kW

## Adjusting EBITDA estimates

We have updated our adjusted EBITDA estimates where we now include the Brunner Island conversion (\$20-\$35Mn estimate) and the impact from the latest forward curves. We continue to include the drag from Harquahala (\$5-10Mn estimate).

2016+ EBITDA and EPS estimates have been reduced to account for the latest commodity mark-to-market

Figure 231: Talen Adjusted EBITDA Estimates

Talen Energy EBITDA Summary	2015	2016	2017	2018	2019
PPL Supply	\$706	\$356	\$150	\$179	\$160
Raven Power	\$121	\$87	\$94	\$97	\$85
Sapphire Power	\$55	\$41	\$32	\$33	\$8
Topaz/Jade Power	\$22	-\$5	\$6	\$11	\$13
MACH Gen	\$44	\$122	\$115	\$112	\$107
Subtotal	\$948	\$602	\$396	\$432	\$373
Synergies and Other	\$134	\$140	\$195	\$190	\$193
<b>Total Adjusted EBITDA</b>	<b>\$1,082</b>	<b>\$742</b>	<b>\$591</b>	<b>\$622</b>	<b>\$565</b>
<b>Combined Guidance</b>	<b>1,050-1,100</b>	<b>635-835</b>			
UBS Prior	1,082	751	589	599	563
Consensus	1,058	745	723	659	648

Source: Company filings, ThomsonReuters, UBS estimates

# TECO Energy Inc.

*Investors will be concentrating on probability of deal closing and related datapoints in New Mexico with hearings set for late May. We continue to expect that the transaction will be completed as TE successfully navigated its own approval of NMGC with largely the same NM Commission. Emera has also “effectively hedged” 85-95% of its currency exposure on the planned financing.*

[TECO does not intend to hold earnings calls at this time](#)

For additional context, please refer links to relevant recent reports below:

[2/23/16 Searching For Clues in Regulated M&A](#)

[10/12/15 Emera Poised to Bottle the Tampa Lightning](#)

[9/4/15 A Sunny Day in Florida](#)

[7/31/15 Lips Are Sealed](#)

[7/16/15 Lightning Strikes in Tampa](#)

[4/29/15 Tapping The Tampa Treasure](#)

[2/10/15 Tampa Thunder: Upgrade to Buy](#)

[12/23/14 The SMID Bid Video](#)

[12/19/14 The SMID Bid: The Context for Regulated M&A](#)

## **What is the pivotal question for TE?**

### **Will Emera successfully close the pending transaction to purchase TECO?**

- New Mexico settlement further de-risks the transaction: On April 11<sup>th</sup> TECO and Emera announced an unopposed stipulation in Emera’s indirect acquisition of New Mexico Gas Company (NMGC) as part of the Emera-TECO transaction. Parties to the settlement include the NM Public Regulation Commission (PRC) Staff, the Attorney General, City of Albuquerque, US DOE, and consumer groups. Key elements of the settlement include:
  - **Rates stability**
    - No new base rate increases prior to YE17. The first ratecase will use a historic test year but future cases can use either historic or future
    - No charge to ratepayers to recover the cost of the acquisition premium
    - Continuation of \$4Mn annual bill reduction credit of \$4 million through June 30, 2018
    - 50% equity ratio until the next ratecase and a maximum of 54% in the next ratecase
  - **Economic development:**
    - NMGC will maintain at least 675 full-time employees for at least three-years and will require Commission approval to decrease below this level after that point. NMGC must also maintain its call center and corporate headquarters locally, subject to Commission approval for certain changes.
    - Commit to capital spending at least 3x depreciation, which implies ~\$100Mn of annual capex versus ~\$63Mn UBS estimates based on prior TE filings
    - Dedicate ~\$20Mn towards local gas infrastructure projects and other economic development at shareholder expense. NMGC also agrees to increase annual donations to \$800K for at least three years
  - **Ownership:** Limitations on parent dividends and cannot sell NMGC for ten years

[Following the comprehensive opposed settlement we continue to expect the transaction will close](#)

Hearings are set to begin May 23<sup>rd</sup> and prior to the settlement TE management had pointed to the timeline for its own acquisition of NMGC as an example where it took six-to-eight weeks for approval following hearings without any issues arising. Based upon this precedent the deal would close around August, consistent with Emera's target (mid-2016) but this could be accelerated after the unopposed stipulation.

[Case No. 15-00327-UT](#)

There has been turnover on the PRC – specifically there are two Commissioners on the PRC who did not vote on the previous NMGC acquisition. Former Commissioner (1999-2006) Lynda Lovejoy ran unopposed and was re-elected with a term beginning January 1, 2015. Sandy Jones is also a newly elected Commissioner.

Aside from New Mexico, TECO has achieved the other key milestones:

- **TECO shareholder vote:** Approved December 3
- **FERC:** Approved January 20
- **HSR:** Waiting period expired February 5
- **CFIUS:** Approved March 23
- **Florida:** Although formal Florida approval is not necessary, Emera and TECO have met with the Florida PSC and had constructive conversations

Prior to the Emera transaction we highlighted the opportunity for TECO to stayout from ratecases in both Florida and New Mexico for longer based upon customer growth and synergy savings – it remains to be seen how that dynamic would be impacted by the Emera transaction. In Florida management reported that construction on Polk is going well and is meeting its schedule/budget expectations.

- **Deal financing significantly hedged:** Emera has secured \$6.5Bn of bridge financing and has begun the placement of permanent financing for the deal. Emera has completed \$C2.2Bn of convertible debentures (\$C1.9Bn plus \$C285Mn underwriter option) and anticipates completing another ~\$1Bn of preferred stock/hybrid securities as part of the deal financing. The debentures are denominated in Canadian dollars and Emera will be converting to US Dollars when in receipt of the funds and has a currency exchange forward contract. The remaining ~\$3.6Bn USD of the acquisition price is expected to be financed with US dollar denominated debt. While there certainly has been pressure on the energy sector (and Canadian Dollar) lately when attempting to secure external financing, we do not perceive those issues spreading to the high quality regulated utility sector and fully expect the TECO transaction to be financed.

**Figure 232: Emera Financing Strategy and Timeline for TECO Transaction**

Expected Ranges for Financing Plan	Amount	Timing
Common Equity and Available Sources	USD\$1.7-\$2.1Bn	3Q15
Preferred Equity/Hybrid Securities	USD\$0.8-\$1.2Bn	Mid 2016
Debt	USD\$3.4-\$3.8Bn	Mid 2016

Source: Company filings (March 2016)

- **Guatemala annulment application denied in favor of TECO's position:** On April 5<sup>th</sup> the International Centre for Settlement of Investment Disputes ruled in favor of TECO Guatemala and against Guatemala's application to annul a previous \$21.1Mn award.

The settlement could accelerate the timeline of approval

How long will TECO be able to avoid ratecases for in NM and FL if the Emera transaction is approved?

Emera has "effectively hedged" 85%-95% of the financing and the bulk of the remaining financing is expected to be in USD

# WEC Energy Group

We expect WEC to provide further updates on its capex 'backlog' (at least qualitatively) to bolster ratebase growth as part of its 'iterative' process to further offset the impact of bonus depreciation.

We expect 1Q16 adjusted EPS of **\$1.00** at the lower-end of the guidance range (\$0.99-\$1.03) but lagging consensus (\$1.04) which is above the range. Heating degree days (HDD) for the quarter are notably below average with March unseasonably mild as we detail for other companies throughout the report. The combination of rate relief (2015 ratecases and the 2014 biennial Wisconsin cases) and O&M control should more than offset the impact of weather and drive YoY growth. WEC is included the contribution Integrys in its adjusted EPS for 2016 and the company's utility earnings are more heavily weighted toward the winter months (approximately 45-50% in the first quarter historically).

The key to achieving 1Q16 and FY16 guidance appears to be "rigorous O&M discipline" as weather appears to be a modest headwind again

4Q15 earnings fell short of consensus for the first time in multiple periods – will there be a repeat performance?

Figure 233: WEC 4Q15 Earnings Walk

WEC Energy 1Q16 Earnings Walk	EPS
<b>1Q15A Adjusted EPS</b>	<b>0.90</b>
Weather vs Normal in 1Q15	(0.05)
Weather vs Normal in 1Q16	(0.03)
Sales Growth: ~30bp	0.00
Rate Relief	
Peoples Gas - IL	0.01
North Shore Gas - IL	0.00
Michigan Gas - MI	0.00
Wisconsin Public Service Corp - WI	(0.01)
Minnesota Energy Resources - MI	0.01
WEPCO & Wisconsin Gas - WI	0.04
O&M and Other Benefit Reductions	0.08
American Transmission Co. (ATC)	0.01
Power The Future (PTF)	0.01
Interest Expense (Ex. TEG)	-
D&A (Ex. TEG)	(0.01)
Net Contribution from Integrys	0.29
Dilution from Integrys	(0.25)
Parent	-
<b>1Q16E Adjusted EPS</b>	<b>1.00</b>
1Q16 Consensus	1.04
1Q16 Guidance	0.99-1.03
2016 UBS EPS	2.93
2016 Consensus	2.93
2016 Guidance	2.88-2.94

Source: Company filings, FactSet, UBS estimates

*For additional context, please refer links to relevant recent reports below:*

[2/16/16 Integrating Integrys](#)

[11/6/15 Inflection in Spend](#)

[10/26/15 Letting Out Some Steam \[Downgrade\]](#)

[7/30/2015 New Beginnings](#)

[5/16/2015 Running Towards the Finish Line](#)

[4/13/15 Clearing the Air Around Deal Accretion](#)

## What are the pivotal questions for WEC?

### **What are the drivers of regulated growth within the 5-7% EPS growth target?**

- **Accelerating capex to offset bonus depreciation:** WEC now expects to book ~\$1Bn of deferred tax cash benefits from the recent five-year extension of bonus depreciation with the majority of the cash coming in from 2016-2017. Management continues to note significant flexibility to accelerate future capital projects in order to reinvest bonus cash and prevent earnings reductions from lower ratebase. WEC anticipates becoming a cash tax payer in 2016 which should allow it to utilize the accelerated depreciation more readily to offset some, if not most, of the impact from reduced ratebase. Management's top priority is to invest excess cash from bonus depreciation into infrastructure but an alternative option is to pay-down higher coupon debt should other ratebase investments not present themselves to the match the full magnitude of excess cash.
- **Integrus synergies could be significant – and management has opened the door:** When announcing the deal in June 2014 management emphasized that they "did not base this transaction on synergies" but now WEC has begun discussing areas for cost savings more explicitly. For example WEC will be reducing headcount and consolidating IT as part of the effort to reduce operating costs. In 2014 Integrus had \$1.2Bn of O&M at its utilities (~60% gas/~40% electric) and every 1% of reduction in just the Integrus cost structure would drive ~\$0.02-\$0.03 FY EPS improvement. Based upon precedent deals we ultimately see the potential for ~3% non-fuel O&M savings for the consolidated company, implying \$0.15-\$0.20 of O&M savings. The 'run-rate' is embedded in our 2020 EPS estimate with the benefit slowly accruing through the years and we look for more signs of progress/updates on the 1Q16 call to further refine the magnitude and timing of savings.
- **Looking towards the next Wisconsin ratecases which represent ~40% of ratebase:** As of March management was still evaluating the timing for the next ratecase in Wisconsin following its April 2015 Wisconsin Public Service (WPS) case which concluded in November (new rates January 1<sup>st</sup>). The previous Wisconsin Electric Power Company (WEPCO) biennial case was filed in May 2014 with new rates effective January 2015 which includes \$26.6Mn uplift in 2016 for the expiration of bill credits. Wisconsin Gas also filed a ratecase at that point with \$21.4Mn incremental revenue in 2016. The previous ratecase included changes to rate design for solar which were appealed and ultimately not implemented; this broad policy issue could be raised again in the upcoming ratecase but is not expected to have a material impact in the near-term. As part of the Integrus merger Wisconsin Gas and Wisconsin Electric each agreed to three years of earnings sharing such that if the utilities over-earn, the first 50bp will be shared equally with customers.

Minnesota Energy Resources filed a \$15Mn case in September 2015 and implemented rates in January subject to refund. Peoples Gas and North Shore Gas have base rate freezes through July 2017 as part of the merger conditions.

With the benefit of time to work on its capex schedule incorporating bonus depreciation cash we expect WEC to move 'backlog' projects into its base plan

WEC broadly discussed staffing, IT, supply chain, customer service, and operations as areas of focus following the TEG merger but has not quantified

Wisconsin Electric and Wisconsin Gas biennial ratecase filings expected in the near term based on management's pattern in the last two sets of cases

WEPCO and WI Gas represent over 40% of YE15 ratebase

- **Riverside approved by Wisconsin PSC:** The Wisconsin PSC approved Alliant's proposed 700MW Riverside plant on March 31<sup>st</sup> which includes an option for WEC's Wisconsin Public Service Corp. subsidiary to purchase a stake in the plant. In our recent conversation with LNT management they stated that they are monitoring the resource plans for MGE and WEC as they also have the potential to add ownership in Riverside (50MW and 200MW respectively) but those possibilities are not yet reflected in the Alliant's capex plan as the decisions would be after construction is completed (2020-2024 with a limit of 100MW in the first two years of the option). If WEC acquires capacity in Riverside then LNT can purchase 200MW of the next WEC CCGT built before 2030 so the impact on Alliant ratebase would largely be offset although there could be lag. The partnership between LNT and WEC originated from WEC opposing Alliant's development plan citing availability of cheaper alternatives to Alliant's proposed facility and highlighting creation of excess capacity in the region. (Docket 6680-CE-176)

The entire Riverside process was somewhat surprising to see a peer utility intervening in an adjacent utilities' resource filing. The benefit to WEC is clear in its ability to amortize its generation portfolio across a wider pool of sales

### Will WEC be able to execute at People's Gas?

- **People's Gas is quiet as of late but pipeline replacement issue still not fully resolved:** On February 9<sup>th</sup> after WEC's FY15 earnings call Illinois Attorney General Lisa Madigan issued a statement alleging that three former People's Gas executives violated Illinois state law by failing to disclose the latest cost estimates for the accelerated pipeline replacement program (AMRP) which were significantly higher than the previous estimates. WEC continues to argue that it had no knowledge of the higher estimates and was not informed by Integrys on this point. According to latest cost estimates filed by Peoples Gas for its AMRP, the target cost is now ~\$6.8bn by 2030 and ~\$7.8bn through 2040 on the system upgrade work. This is significantly lower than earlier estimates - before WEC's acquisition of Integrys. The spending trajectory had suggested the program could have ended up costing ~\$9.4bn through 2030 and ~\$11bn through 2040. That said, even under the new projections, *under a "contingency case" estimate - which factors in higher restoration costs - the program could cost ~\$8.3bn by 2030 and ~\$9.7bn by 2040.*

As a reminder the latest target cost is now ~\$6.8Bn through 2030 and ~\$7.8Bn through 2040

We expect an increased operational focus as execution on the planned Illinois Gas Main replacement program progresses under new leadership and elevated scrutiny

Despite the political developments, WEC is still spending and recovering its capital investment on the AMRP. Annual spending is expected to be ~\$250-300 Mn annually with an inflation cap on the bill impact. Overall we are encouraged by the fact that People's Gas earned its allowed ROE in 2015 (9.05%) and we look to see if management can deliver repeat performance in 2016.

## Earnings estimates largely unchanged

We show below our earnings forecast with WEC standalone in 2014/2015 and combined WEC+TEG in 2016+. Our estimates are in-line with consensus through 2018 but are slightly lower in 2019/2020. Our estimates are largely unchanged and continue to reflect a 5.7% CAGR from 2016-2020.

Management expects its utilities to earn their allowed ROEs as they did in calendar 2015

Figure 3: WEC EPS estimates vs. pro-forma for the merger with TEG, 2014A-2020E

	2014A	2015A	2016E	2017E	2018E	2019E	2020E	CAGR '17-'20
<b>UBSe Combined Entity</b>		<b>\$2.73</b>	<b>\$2.92</b>	<b>\$3.09</b>	<b>\$3.30</b>	<b>\$3.44</b>	<b>\$3.63</b>	<b>5.7%</b>
<i>UBSe (Prior)</i>	\$2.65	\$2.73	\$2.93	\$3.09	\$3.30	\$3.43	\$3.63	
<i>Consensus</i>			\$2.93	\$3.10	\$3.30	\$3.50	\$3.70	
Embedded synergies assumption % of O&M (UBSe)		-0.5%	0.5%	1.0%	1.5%	2.0%	3.0%	
Embedded synergies assumption (UBSe)		\$0.00	\$0.02	\$0.05	\$0.08	\$0.11	\$0.16	
<b>EPS Guidance</b>			<b>\$2.88-\$2.94</b>		<b>5-7% EPS Growth beyond 2016</b>			
Low-			\$2.88	\$3.02	\$3.18	\$3.33	\$3.50	
High			\$2.94	\$3.15	\$3.37	\$3.60	\$3.85	
Midpoint of new EPS Guidance Growth			\$2.91	\$3.08	\$3.27	\$3.47	\$3.68	6.0%
<i>Dividend</i>	\$1.56	\$1.83	\$1.95	\$2.00	\$2.06	\$2.13	\$2.19	
<i>Dividend Growth</i>		17.3%	6.3%	3.0%	3.0%	3.0%	3.0%	
<i>Payout Ratio</i>	59%	67%	67%	67%	66%	66%	65%	
<b>Dividend Guidance</b>	<b>14%-15% growth in 2015 and 65%-70% payout in 2017</b>							

Source: Company filings, FactSet, UBS estimates

## How conservative is 2016 guidance?

In 4Q15 WEC's quarterly earnings missed consensus for the first time in recent history (previous misses were September 2009) as unfavorable weather dampened results. This caused FY15 earnings to come in 'only' in-line with guidance (\$2.73 actual adjusted EPS compared with \$2.67-\$2.77 guidance) while management exceeded the top-end of its guidance range in 2009-2014. Although 1Q16 weather appears to be a modest headwind, management likely incorporated a larger than usual measure of conservatism in its \$2.67-\$2.77 FY16 adjusted EPS guidance.

WEC has set a high bar for itself after management has continually surpassed expectations based on what we see as conservative guidance

# Westar Energy

All eyes are on management to see whether they confirm media reports that the company is accepting bids as part of a broad strategic review. WR has historically traded at a discount but is now at a ~18% premium vs. 7% discount approximately one year ago. After the flurry of M&A earlier this year and volume of bidders for EME in its competitive process, we view the media reports as credible.

We expect WR to report adjusted 1Q16 EPS of **\$0.47**, slightly below consensus (\$0.48) as weather dings results. Unlike many other utilities, Westar had normal weather in 1Q15; therefore, the weather comparison is a non-factor. Growth from Kansas rate relief and higher transmission rates forms the foundation for growth but is offset by higher D&A and dilution. Management is targeting to keep non-tracked O&M and SG&A flat which should allow a disproportionate amount of revenue from new rates to accrue to earnings. Management has already disclosed that it booked \$6.5Mn of COLI proceeds in 2016 on the February 25<sup>th</sup> 4Q15 earnings call versus \$16Mn FY16 guidance.

**Figure 234: WR 1Q16E Earnings Walk**

1Q16 Earnings Walk	
<b>1Q15A Adjusted EPS</b>	<b>\$0.38</b>
Weather vs Normal in 1Q15	\$0.00
Weather vs Normal in 1Q16	(\$0.03)
Rate increase - Oct 28, 2015	\$0.11
Energy Marketing in 1Q15	\$0.00
Retail Sales Growth: 50 bps	\$0.00
Transmission Rates (TDC)	\$0.03
Environ. Cost Rider (ECRR)	\$0.00
Transmission Refund	\$0.00
O&M	\$0.00
D&A	(\$0.04)
AFUDC	\$0.01
Interest Expense	\$0.01
Share Dilution	(\$0.02)
Eff. Tax Rate ~33.5% to 36%	(\$0.01)
COLI Proceeds	\$0.05
<b>1Q16E Adjusted EPS UBSe</b>	<b>\$0.47</b>
1Q16 Consensus	\$0.48
2016E UBSe	\$2.38
2016E Consensus	\$2.44
2016 Guidance	\$2.38-\$2.53

Source: Company filings, FactSet, UBS estimates

*For more detail on these issues, please see our other recent reports:*

[2/29/16 Bonus Blows Away Some Wind Growth](#)

[1/25/16 Winning With Wind?](#)

[11/5/15 Fair Winds into 2016](#)

[10/8/15 A Compassionate Clean Power Plan](#)

[8/6/15 Where will the ROE Land?](#)

[5/7/15 One ROE Revision Reflected, One To Go](#)

[5/6/15 Taking A Dose of Transmission Medicine](#)

[3/2/15 Entering the Bullring](#)

## **What are the pivotal questions for WR?**

### **What do the latest Westar media reports indicate?**

- **In surprising twist, AEE is reportedly interested in Westar:** On April 8<sup>th</sup> Bloomberg reported that Ameren was among parties bidding for Westar; while coherent in the near adjacency of the service territories, we saw the news as surprising. AEE has recently established a new growth rate of 5-8% with recent 4Q results, rolling forward expectations ahead of Street expectations with a top- quartile ratebase growth profile of 6.5%. Many companies of late exploring transactions have largely had earnings deficiencies in which they failed to meet their earnings growth targets, seeing a levered deal as an alternative to reducing expectations. The article further suggests the bid could include yet another Canadian entity (Borealis) following a similar bid on neighboring Empire District by Canadian company Algonquin in recent weeks.

We are *not* surprised to see Westar back in the news over M&A following the latest slew of small-and-mid cap transactions including EDE as mentioned but also TE, ITC, CNL, and others. Following media reports, Westar has not issued a press release to confirm the sales process, which has been typical of other recent deals, including EDE and TE. Management has repeatedly stated in recent years the merits of scale to M&A. We note the stock has been volatile of late following weaker 4Q updates; that said, we suspect investors may not appreciate the uplift afforded by the Production Tax Credits (PTCs) from its latest wind initiative and over-estimate the rate lag effects during the pendency of its latest rate stayout.

- **Risk that debt could be imputed in Missouri could complicate a transaction:** We also see a risk that the Missouri Public Service Commission could impute the holding company leverage when calculating the authorized equity ratio which would reduce the economics of any deal. Furthermore WR was created by merging two local Kansas utilities and we perceive some degree of execution risk if a transaction involves an out-of-state buyer.
- **CEO's relationship with Ameren's nuclear plant:** Adam Heflin was named the CEO and Chief Nuclear Officer (CNO) at Wolf Creek Nuclear Operating Corporation (WCNOC), a subsidiary of Westar Energy, in January 2014. Wolf Creek is one of Westar's most significant assets standing at 551 MW of owned-capacity. Along with years of experience in the nuclear industry, he brought along a relationship with Ameren Missouri's Callaway Energy Center. Following media reports linking Ameren and Westar, we note the familiarity with Wolf Creek and Callaway.

**We note substantial interest in EDE (8 bidders listed out in the proxy) as indicative of continued M&A interest for Midwest utilities**

## How much revenue attrition will WR suffer without a rate increase until 2019?

- We expect ~60 bps of lag in 2017 and 2018 before a rate increase, with ~20 bps of lag in 2019 (each 25 bps ~ \$0.05 EPS). Aside from the recent acquisitions of the Western Plains and Kingman Wind farms, no large capital intensive projects are expected through the end of the decade, likely mitigating most regulatory lag through the next ratecase filing, expected in mid/late-2018. This next filing is expected to deal with expiring PTCs for some of the older existing wind projects in WR's fleet. With the next ratecase not until mid-2018 (for 2019 rates), we continue to estimate only about \$0.02 dilution from the recently acquired 280-MW Western Plains Wind Farm and 100 MW (50%) of the Kingman Wind Energy Center while the company collects production tax credits (PTCs) in lieu of higher rates through 2019.
- **Next rate filing not currently planned until mid/late-2018:** Management had previously stated that with no large capital intensive projects forthcoming there would likely be little regulatory lag through the next ratecase filing, expected in mid/late-2018 to deal with expiring PTCs for some of the older existing wind projects in WR's fleet. However, at less than \$20/MWh production cost, wind is now competitive even with WR's \$1.80/MMbtu coal cost (~\$20/MWh) and management is keen to lock in these rates. Furthermore, as illustrated in the Figures below, the use of bonus depreciation tax deductions and the recent extension of the wind production tax credit (PTC) could allow the company to fund depreciation, interest, and operating costs at close to breakeven while awaiting a rate increase.
- **Coal plant retirements this year saves O&M:** In addition to incremental wind, meeting CPP targets is also likely to require the either the early retirement or conversion to gas of smaller and older coal units. On Oct 12, WR announced the closing of units at Tecumseh, Hutchinson, and Lawrence by the end of 2015. In terms of future opportunities, we note the expiration of sale/leaseback arrangement for LaCygne Unit 2 in 2029.

A gas steam turbine unit is also being considered for retirement as well. Compliance is also likely to require the elimination of shoulder period off-system sales from the fleet, which will increase customer costs as expected margins from these sales have been passed back to customers through the fuel clause. A benefit of early unit retirements is the incremental O&M savings, which could help with earned ROE and mitigate the need for ratecases.

The low cost of wind and the PTC extension is pushing WR to acquire more, sooner

Compliance is also likely to require the elimination of shoulder period off-system sales from the fleet, which will increase customer costs

## Maintain \$47 price target, which reflects a 50% probability of an acquisition following the strategic review media reports

Our valuation is based on a 2018 sum-of-the-parts methodology where we assign a 50% probability to a successful acquisition at the average of recent small/mid-cap deal P/Es of 19.3x 2018E. With WR's projected ratebase growth at about the industry average of ~5% through 2020, we are inclined to view the company as less likely to be a strategic target of another utility, with any possible deal more likely to be focussed on yield rather than growth (e.g. more typical of an infrastructure fund).

**Figure 235: WR Valuation now based on a 50% probability of a deal at the average recent deal premium**

Westar Sum of the Parts Valuation - 2018E UBSe									
All US \$Mn except per share data									
	EPS		P/E Multiple			Equity Value			
		Low	Peer Multiple	Prem /Disc	Base	High	Low	Base	High
Distribution	\$1.88	15.9x	16.5x	1.4x	17.9x	19.9x	\$4,269	\$4,806	\$5,343
Transmission	\$0.63	14.5x	16.5x	1.4x	17.9x	19.9x	\$1,310	\$1,617	\$1,797
COLI	\$0.10	14.5x	16.5x	0.0x	16.5x	18.5x	\$218	\$248	\$278
<b>M&amp;A Premium</b>									
Average Implied Deal P/E (ex Duk-PNY)			19.3x						
Premium over peer average multiple			2.8x						
Probability of deal			50%						
Applied deal premium			1.4x						
<b>Total / Implied Utilities</b>	<b>\$2.62</b>	<b>15.5x</b>			<b>17.8x</b>	<b>19.8x</b>	<b>\$5,796</b>	<b>\$6,670</b>	<b>\$7,418</b>
2018E Number of Shares Outstanding (Mn)							142.9	142.9	142.9
<b>Equity Value per Share</b>							<b>\$41.00</b>	<b>\$47.00</b>	<b>\$52.00</b>

Source: Company filings, FactSet, UBS estimates

We are maintaining our EPS estimates below.

**Figure 236: Westar EPS Estimates**

Westar EPS Estimates	2013A	2014A	2015E	2016E	2017E	2018E	2019E
UBSe	\$2.27	\$2.41	\$2.12	\$2.38	\$2.52	\$2.62	\$2.75
Prior estimate	\$2.27	\$2.41	\$2.12	\$2.38	\$2.52	\$2.62	\$2.75
Consensus	\$2.27	\$2.35	\$2.11	\$2.44	\$2.53	\$2.62	\$2.82
Guidance			\$2.38-\$2.53				
Authorized ROE (Implied)		10.00%	9.35%	9.35%	9.35%	9.35%	9.35%
Regulatory lag & other		-0.86%	-1.71%	-0.37%	-0.60%	-0.55%	-0.25%
Earned Kansas Dist ROE		9.14%	7.64%	8.98%	8.75%	8.80%	9.10%
EPS CAGR off midpoint of 2015 guidance \$2.21 (guidance 4%-6%)						5.7%	5.5%

Source: Company filings, FactSet, UBS estimates

# Xcel Energy

*Expect a small miss on mild weather and higher depreciation, partially offset by higher rates.*

With mild weather in 1Q16 (vs. a close-to-normal 1Q15), we expect a -0.04 miss at \$0.46 vs. consensus \$0.50. Rate increases (including capital riders) of +\$0.08 and a penny of increased transmission earnings are offset by a dime of higher interest, taxes, depreciation, and O&M, as well as a year-over-year decline in AFUDC.

**Figure 237: XEL 1Q16 vs. 1Q15 Walk**

XEL 1Q16 Earnings Walk	EPS
<b>1Q15 EPS</b>	<b>\$0.46</b>
Weather Normal	\$0.01
Milder than Normal Weather	(\$0.03)
Sales Guidance (+0.5% to +1.0% elec, flat gas) had leap year impact	\$0.02
<b>Rate Cases</b>	
Minnesota \$164M interim rates in Jan 2016	\$0.05
Wisconsin elec \$7.6M final rates in Jan 2016	\$0.00
Wisconsin gas \$4.2M final rates in Jan 2016	\$0.00
CO-electric (-\$39.4M 3-yr plan base decrease effective Feb 13 2015)	(\$0.01)
CO-gas (\$40M interim rate, offset by a reserve Oct 2015)	\$0.02
Capital Rider Revenue (70-80M increase)	\$0.02
Transmission revenue, net of costs	\$0.01
NSP-Wisconsin fuel recovery	\$0.00
Increased taxes (35.5% in 1Q15 to normal 34%-36%)	\$0.00
Interest Expense (40-50 increase 2H loaded)	(\$0.01)
O&M (0-2% growth in 2016)	(\$0.01)
AFUDC (10-15 decrease)	(\$0.00)
Property Taxes (40-50 increase)	(\$0.01)
Depreciation (200 increase)	(\$0.06)
Other	\$0.00
Dilution	(\$0.00)
<b>1Q16 EPS</b>	<b>\$0.46</b>
<b>1Q16 Consensus</b>	<b>\$0.50</b>
<b>2016 Earnings Guidance</b>	<b>2.12-2.27</b>
<b>2016 UBSe</b>	<b>\$2.20</b>
<b>2016 Consensus</b>	<b>\$2.20</b>

Source: Company filings, UBS estimates, FactSet

## What are the prospects for increased capex?

XEL's new \$2.5Bn 2016-2020E upside capex plan (up from \$1.6Bn at the December Analyst Day) includes opportunities that span the risk spectrum including from grid modernization (higher probability of success) to ratebasing natural gas reserves (lower probability of success). We specifically focus on solar where we see the extension of the Investment Tax Credit (ITC) as benefitting unregulated developers who do not have to normalize the ITC and therefore can offer more attractive customer benefits. **We see it as increasingly challenging to execute on ratebase solar capex for all utilities following the ITC extension, with XEL among the few explicitly reflecting it in their plans.**

If fully implemented through 2020, this would drive ratebase growth back up to ~5.5% and EPS growth 5.5%-6.0% off a 2015 \$2.10 base (still assuming a 9.4% ROE). This would be in-line with the previous upside-case forecast for ~5.6% ratebase growth and 5%-6% EPS growth. However, with much of the upside spending in 2018 and beyond, this leaves management with slower near-term EPS

**We expect a formal Colorado IRP filing in early May that will include the possibility of ~\$850M "upside" ratebase spend for 50% of the plan for a total 600 MW wind and 400 MW solar**

**In contrast, XEL's \$2.5B of upside capex includes ~\$500M of ratebasing in Minnesota for only 25% of the IRP there that calls for a total 800MW wind and 400 MW solar**

growth and a "show-me" story for 2018+ to justify the average utility multiple XEL now trades at. More specifically, the latest Oct 2nd update to the Minnesota Integrated Resource Plan (IRP) includes (among other things) 800 MW of new wind and 400 MW of new solar by 2020. Likewise, the recent Colorado energy plan includes 600 MW of wind and 400 MW of solar. Of these totals, only a portion is expected to be ratebased, with the \$2.5B (~100-150 bps of growth) inclusive of about 200 MW of wind and 100 MW of solar in MN and another 300 MW of wind and 200 MW of solar in Colorado.

**Ratecase updates:** Intervenor testimony is expected in June for the multi-year Minnesota ratecase filed in Nov 2015 (currently in discovery). As expected, SPS also filed a **new ratecase in Texas** on Feb 16<sup>th</sup> seeking a \$72M increase based on a 10.25% ROE on 53.97% of \$1.7B ratebase during a year-end 9/30/2015 test year (updated through Jan 2016 under the new law – see below). In **Wisconsin** on April 1, NSP filed limited-issue electric and gas ratecases for \$28M elec/\$5M gas increases based on \$1.2B elec ratebase with no change to 10.0%/52.49% authorized ROE/equity ratio. The increase is for recovery of fixed generation/transmission charges, fuel and purchased power, ratebase investment, and environmental remediation from manufactured gas.

## Valuation, Estimates and View

Our estimates are unchanged. As we note below, our ratebase projection and estimates through 2018 were reduced after the 4Q call with a \$1.5B ratebase pickup from upside spending in 2019 and 2020. While we have been impressed with the execution of regulatory strategy at XEL, we downgraded to Sell in February after 10% outperformance since June. The stock now trades in-line with peers despite EPS growth pressure. Our Sell rating reflects the need for management to earn an in-line multiple though the execution of significant upside capex to offset the negative impact of bonus depreciation on ratebase growth and the slower build-up for competitive transmission.

We continue to acknowledge that last year's multi-year settlement in Colorado, and legislation passed in Minnesota significantly reduces regulatory risk, with ~68% of ratebase now under multi-year rate plans. Currently earning an overall utility 8.91% ROE (12MT Dec 2015), the company plans to further reduce regulatory lag through recently passed legislation in Minnesota and Texas, particularly in Minnesota where ~75% of such lag originates.

**Figure 238: UBS estimates for XEL, 2014A-2020E**

<i>UBS Estimates (\$/share)</i>	2014A	2015E	2016E	2017E	2018E	2019E	2020E
PSCo	\$0.90	\$0.92	\$0.95	\$0.97	\$1.01	\$1.06	\$1.11
NSPM	0.80	0.95	1.01	1.02	1.03	1.07	1.13
SPS	0.26	0.25	0.30	0.35	0.38	0.42	0.47
NSPW	0.14	0.16	0.14	0.16	0.17	0.18	0.20
XEL Parent	(0.08)	(0.18)	(0.21)	(0.19)	(0.19)	(0.17)	(0.16)
<b>UBSe EPS</b>	<b>\$2.03</b>	<b>\$2.09</b>	<b>\$2.20</b>	<b>\$2.30</b>	<b>\$2.40</b>	<b>\$2.55</b>	<b>\$2.74</b>
<b>CAGR 2015 \$2.10 (mdpt guide) - 20XX</b>					<b>4.6%</b>		<b>5.5%</b>
<i>Guidance</i>			<i>2.12-2.27</i>				<i>4-6%</i>
Previous Ests			\$2.20	\$2.30	\$2.40	\$2.55	
Consensus			\$2.20	\$2.33	\$2.44	\$2.55	–

Source: Company filings, FactSet, UBS estimates

## Guidance remains unchanged

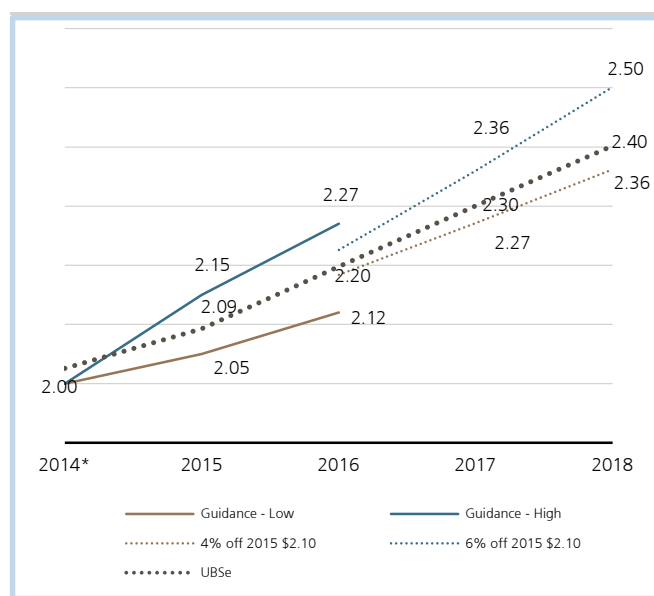
At the analyst day in December, management rebased the 4%-6% EPS growth projection off the \$2.10 midpoint of 2015 guidance (vs. the prior weather normalized \$2.00 for 2014). This rebasing didn't change the midpoints of projections through 2018, but it did have the effect of narrowing the range somewhat beyond 2016. Our reduced estimates are now toward the lower end of the range through 2018.

**Figure 239: Guidance Assumptions: 2016**

Guidance	2016
Weather adjusted retail elec sales	0.5%-1.0%
Weather adjusted nat gas sales	flat
Capital rider revenue	\$70 to \$80Mn Inc.
O&M expense	0%-2%
Depreciation expense	\$200Mn Inc.
Property tax expense	\$40 to \$50Mn Inc.
Interest (net of AFUDC debt)	\$40 to \$50Mn Inc.
AFUDC - Equity	\$10 to \$15Mn Dec.
Effective Tax Rate	34% - 36%
Average C/S Outstanding	509Mn
Operating EPS Growth Rate	5.0% to 7.0%
Annual Operating EPS Guidance	\$2.12 to \$2.27
Dividend Growth Rate	5.0% to 7.0%

Source: Company filings

**Figure 240: UBS estimates vs. Guidance, 2015E-2018E**



Source: UBS estimates, company filings

## No cash taxes through at least 2018 – and no material impact from bonus either

Longer-term, management expects no material impact to EPS growth through 2018 from bonus depreciation considering the company's NOL tax position and the impact of multi-year rate plans. With XEL today not a cash tax payer, balance sheet benefits from lower taxes would only begin to accrue in 2018, although this is prior to incremental wind build in ratebase that could delay cash benefits from bonus depreciation even further.

XEL still does not anticipate issuing any additional equity and will even fund its dividend reinvestment program and benefit programs from share repurchases through the period. A "modest" level of equity could be needed to fund the \$2.5B "upside" capital program, although even this could be unnecessary given the cash benefits from the extension of bonus depreciation. XEL has authorized purchases of up to 3M shares for stock compensation plan settlements. *The company emphasized that any upside capex would likely be a backend weighted in 2018+, suggesting any possible corresponding equity would also be backend weighted.*

**No equity at all through 2020 under base capital program**

## Valuation: Increasing price target \$3 to \$39 on higher average peer P/E multiple and roll forward to 2018E

We've rolled our SOP forward to a 2018E average utility P/E methodology with a premium ascribed to Wisconsin for its above-average ROEs (1.0x-turn) and a

discount for the Southwest. We have increased the Southwest discount to 1.0x-turn from 0.5x-turn previously due to the relative regulatory lag and uncertainty at the subsidiary.

**Figure 241: XEL Valuation**

Business Segment	Valuation Metric	2018 EPS	Low Case		Premium/Discount	Base Case		High Case	
			Valuation Multiple	(\$/Share) Value		Valuation Multiple	(\$/Share) Value	Valuation Multiple	(\$/Share) Value
Regulated Business					Regulated Peers:		16.1x		
Northern States Power - Minnesota	P/E	\$1.03	15.1x	\$15.59	0.0x	16.1x	\$16.62	17.1x	\$17.66
Northern States Power - Wisconsin	P/E	\$0.17	16.1x	\$2.66	1.0x	17.1x	\$2.83	18.1x	\$3.00
Public Service Colorado	P/E	\$1.01	15.1x	\$15.26	0.0x	16.1x	\$16.27	17.1x	\$17.28
Southwestern Power Service	P/E	\$0.38	14.1x	\$5.38	-1.0x	15.1x	\$5.76	16.1x	\$6.15
HoldCo									
Parent & Other Overhead Expense	P/E	(\$0.13)	15.1x	(\$2.01)		16.1x	(\$2.14)	17.1x	(\$2.28)
XEL Equity Value per Share		\$2.46	15.1x	\$37.00		15.9x	\$39.00	17.1x	\$42.00

Source: Company filings, FactSet, UBS estimates

*For more detail on these issues, please see our other recent reports:*

[2/3/16 Too Much, Too Fast](#)

[12/7/15 Upside from the Analyst Day](#)

[11/2/15 Ramping Up on Renewables](#)

[7/31/15 Executing Well on Regulatory Strategy](#)

[5/4/15 Fighting Off a Case of the Lag](#)

[4/6 In Search of Reform](#)

[1/30 Rocky Mountain Higher](#)

[11/3 Poised for Further Inflection?](#)

## UBS ratebase forecast is reduced, with back-end-loaded recovery

In February, we reduced our ratebase growth forecast through 2020 from a 5.0% CAGR to 4.8%, although it now tracks along at the base plan's 3.7% through 2018, with a \$1.3B pickup from "upside" capex in 2019 and 2020. The result of this new pattern was to reduce our estimates by about -\$0.05 through 2018 with a recovery back toward our original 2020 estimate as the additional spending fills the hole created by bonus depreciation.

**We continue to assume 5% ratebase growth and 5.3% EPS CAGR through 2018**

**Figure 242: XEL Ratebase Growth, UBS estimates vs. Base Plan 3.7% Guidance**

Projected Ratebase Growth (Mn)							
	2015	2016	2017	2018	2019	2020	5-yr CAGR
<b>UBSe</b>							
NSPM	9,369	9,815	10,118	10,500	11,129	11,768	4.7%
PSCo	8,916	9,225	9,504	9,785	10,242	10,852	4.0%
SPS	2,882	3,101	3,400	3,644	3,817	3,946	6.5%
NSPW	1,097	1,172	1,258	1,365	1,452	1,547	7.1%
Total UBSe	22,265	23,313	24,281	25,294	26,640	28,113	4.8%
Previous UBSe	22,180	23,514	24,746	26,035	27,248	28,332	5.0%
<b>Base Plan Guidance (New)</b>							
Base Plan Guidance (New)	22,300	23,400	24,300	25,300	26,200	26,800	3.7%
Base Plan Guidance (Previous)	22,300	23,600	24,600	25,900	27,000	27,800	4.5%
Delta (UBSe-Mgmt)	(35)	(87)	(19)	(6)	440	1,313	

Source: Company filings, UBS estimates

**Upside capex:** Incremental capital program from 2016-2020 of a total potential \$2.5B would increase ratebase CAGR to ~5.5%. This is driven by five broad categories disclosed at the Analyst Day, including:

- **Clean Power Plan**, including only a small 25% portion of the NSP-**Minnesota** Integrated Resource Plan (IRP) that calls for a total 800 MW of wind and 400 MW of solar through 2020 (the upside ratebased assumption is only 200 MW of wind and 100 MW of solar for ~\$500M of the \$2.5B upside). *See below for IRP details.* Separately, the **Colorado** "Our Energy Future" plan calls for a total 600 MW of wind and 400 MW of solar, with XEL's upside capex plan assuming 50% is ratebased for ~\$850M (300 MW of wind and 200 MW of solar). We expect a formal Colorado IRP filing in early May.
- **Implementation of grid modernization** plans through rider recovery in MN. Initial installation of Advanced Metering Infrastructure (AMI) across the system. This appears further scalable off the current base, but the economics are less attractive given the \$300 Mn allocated would replace existing AMR meters (which already do not involve meter readers).
- **Ratebasing of natural gas reserves** for 25% of Colorado LDC requirements over 10 years for about \$300M. XEL is exploring the possibility of ratebasing natural gas reserves as well as pipelines for both its natural gas utility as well as its generating fleet in order to capture the current low price environment for customers. PSCo filed an application with Colorado regulators and management expects potential investment in 2H16; this would be done in conjunction with STR's Wexpro unit in UT. In contrast to Questar, XEL's PSCo unit would be limited to an ROE tied +/-100bp vs. their authorized ROE. The Colorado Commission has 240 days to reach a decision on the regulatory framework. *We sense this is the upside in the capex with the relative least likelihood.* Roughly \$300 Mn was allocated to this bucket in the upside vs. \$500 Mn now disclosed for the 10-year period (ratable deployment would suggest ~\$300 Mn is an appropriate approximation for current 5-year outlook).
- **"Steel for fuel":** the acquisition of existing Power Purchase Agreements (PPA) for inclusion in ratebase for the benefit of customers over the long run with minimal price impacts. For example, Cortenay, Rocky Mt., Blue Spruce. Xcel received approval from both the Minnesota and North Dakota Commissions for its proposed Courtney wind project, which can now be included in the ratebase as opposed to a PPA framework and is now under construction for year-end 2016 in-service. We emphasize Calpine would arguably be a good candidate to continue to see assets eventually sold into ratebase as well following its recent success in expanding its Mankato facility (price is the key question). *\$300 Mn was allocated here as an upside acquisition placeholder.*

**How expensive is wind and solar?** Management estimates that wind PPAs are currently being signed at ~mid-\$20's/MWh and solar in the ~\$75/MWh context. The utility will attempt to own ~50% of the opportunity, albeit we suspect an explicit deal on ownership remains challenging.

- **Transmission asset growth**, chiefly through a robust OpCo pipeline. With SPS no longer providing retail electric service in Kansas and Oklahoma, XEL took the opportunity to seed its independent Transcos with ~\$100M of 345-kV line (230 miles). A final approval on transfer from various state and Federal agencies is expected to take a year. Management hopes the assets will add gravitas to the Transcos in future FERC 1000 competitive bidding. The company continues to downplay incremental competitive opportunities, with projects

**What are some of the components of the upside plan?**

**\$300Mn natural gas reserve**  
**\$900Mn of incremental Colorado renewables**  
**Majority of remainder is Minnesota – primarily renewables**

only materializing in the ~4Q16 timeline for MISO at the earliest. Bottom line, projects contemplated are strictly reflective of what is already approved.

*At the recent analyst day, transmission did not feature as prominently within the capex budget and growth opportunities as previous presentations – and seemingly rightly so. We give management credit for not setting forward transmission capex expectations too high given its core territories sit atop the much discussed SPP and MISO regions.*

- **Minnesota revised Integrated Resource Plan (IRP) filed; Accelerating renewables and planning an early shutdown of Sherco Units 1&2.** On Oct 2 XEL announced a revision to its long term resource plan, initially released in March. The plan would reduce carbon emissions by 60% in 2030 vs. 2005 levels, with 63% of NSP system energy carbon-free by 2030. Instead of running the Sherco coal units through 2030 as originally planned, XEL announced that Unit 2 will cease operating as a coal-fired unit in 2023 and Unit 1 will stop coal-fired generation in 2026 (combined nameplate capacity of about 1,530 MW). We see the closures as positive for incremental capex, with the two coal units accounting for ~20% of Minnesota's fleet capacity. The company still plans to add 1,800 MW of wind and 1,400 MW of solar by 2030, but now the company will accelerate the acquisition of 400 MW of utility scale solar and an additional 200 MW of wind resulting in a total 400 MW of large solar and 800 MW of wind over 2018-20. Sherco coal units will be replaced with a 780MW CCGT by 2026 and the company also plans to add another ~230MW CCGT in North Dakota by 2025. Additionally, XEL intends to operate both of its Monticello and Prairie Island nuclear plants through their current licensed period expire in 2030. Following years of pressure on its consolidated EPS growth rate, we see company as increasingly in a position to capitalize on its higher growth rate trajectory. *See below for details.*
  - For the renewable resources alone, we suspect this could add ~\$1 Bn of capex (50% Self-Owned \* 1.5/kW on Wind and 50% Self-Owned \* 400 MW on Solar @ \$1.5/W). Ideally management would target 100% ownership, however recent RFPs have yielded 50%.
  - Recovery of renewable spend could be potentially executed on a little used fuel clause rider, rather than waiting for a full ratecase to enable recovery of these modest increments. We expect more on this in coming quarters closer to execution.
  - The plan includes addition of a CC unit at Sherco which may be required for system stability, and potentially converting a Sherco Unit to use natural gas; and also a CT unit in North Dakota. We show below the capacity additions under the revised long term resource plan as well as the generation mix now and in 2030 envisioned in this plan (in the table below, XEL shows the North Dakota CT coming on line in 2023 for planning).

**Figure 34: Revised Proposal Expansion Plan (MW Additions)**

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Large Solar	-	-	-	200	-	200	100	100	100	100	100	100	-	400	-	-	1,400
Wind	-	-	-	-	800	-	-	200	200	-	400	200	-	-	-	-	1,800
North Dakota	-	-	-	-	-	-	-	-	232	-	-	-	-	-	-	-	232
CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sherco Gas Conversion/CT	-	-	-	-	-	-	-	-	-	-	562	-	-	-	-	-	562
Sherco CC	-	-	-	-	-	-	-	-	-	-	-	778	-	-	-	-	778
CT	-	-	-	-	-	-	-	-	-	-	-	464	-	-	-	-	464
CC	-	-	-	-	-	-	-	-	-	-	-	-	778	-	-	-	778
Total MWs	-	-	-	200	800	200	100	300	532	100	1,062	1,542	778	400	-	-	6,014

Source: Xcel Energy filing, Docket E002/RP-15-21

- **MN ratecase filed at just 3 years.** Management filed on Nov 2 for a 3-year deal in MN rather than the full 5 years it could conceivably file for under the new legislation there, seemingly in an attempt to make it more palatable to interveners skeptical of the process. Recall while management will lock in base rates, it will have access to riders to allow for other spend-recovery (principally renewables). The plan is driven by capital investment and includes interim rates for both 2016 and 2017, with a final decision expected in 1Q2017.
- **Can MN implement interim rates still?** OAG is pushing back of late on a further interim rate step-up in 2017; interim rates however for 2016 will continue to be implemented as expected.
- **However, with a history of settlements,** management expects a settlement or other mediation to ultimately shorten the timeline for a final decision. The case reflects investments made in ratebase and PPA wind parks, for which the legislation there should allow the company to establish a baseline for a formula approach. At a minimum, with no real issues relating to development of the wind parks, the case should prove less controversial than the latest case with the cost over-runs relating to Monticello nuclear uprate. Moreover, with its authorized ROE recently revised to 9.72%, downside risk is more limited.
- **Reduced regulatory lag – eventually – under new legislation in Minnesota.** With the bill signed into law in June 2015, we estimate that its provisions will improve XEL's overall regulatory lag by roughly 30 bps (by 2018) as a result of longer plans, more formulaic rider mechanisms, recovery of O&M based on a price index, the implementation of interim rates during ratecases, the use of the nuclear depreciation surplus to smooth out revenue fluctuations and mitigate increases, and other protections. As a reminder, XEL historically experiences ~100 bps of regulatory lag overall, with ~75 bps from Minnesota, ~20 bps from SPS, and the remainder amongst the remaining jurisdictions. We note, however, that 2016 guidance embeds a low-9's ROE assumption, with little improvement in regulatory lag next year.
- **Another Texas case filed** on Feb 16<sup>th</sup> seeking a \$72M increase based on a 10.25% ROE on 53.97% of \$1.7B ratebase during a year-end 9/30/2015 test year (updated through Jan 2016 under the new law – see below). Expect any real uplift from legislation to accrue in 2017 rather than 2016 (and hence not reflected in the latest EPS guidance).

**2016 guidance embeds a low-9's ROE assumption, with little improvement in regulatory lag next year**

- **No forward-looking test year treatment yet in Texas.** On Dec 17, SPS received an order to reduce electric rates -\$4M based on a historic 2014 test year and a 9.7% ROE on 51% of \$1.4B ratebase. This follows the Administrative Law Judge (ALJ) recommendation in Oct for a rate increase of ~\$1.2M, based on ROE of 9.7% and an equity ratio of 53.97% on a historic test year against XEL's request of a \$42M increase based on a 10.25% ROE on \$1.56B of ratebase. New rates are effective in January but retroactive to June 11, 2015. We note that the company had initially filed the case to take advantage of forward-looking test year treatment as allowed under new legislation.
- **Further background on Texas: Legislation to reduce regulatory lag in Texas was signed into law** in June 2015. While not as impactful on ROEs as the Minnesota legislation, provisions include the ability to implement temporary rates or surcharge 155 days after ratecase filing date and the addition of post-test year capital additions up to 30 days before ratecase filing date. New natural gas generation may be included in ratebase as long as it is in service before the proposed effective rate date.
- **Limited-issue ratecases in Wisconsin.** On April 1, NSP filed limited-issue electric and gas ratecases for \$28M elec/\$5M gas increases based on \$1.2B elec ratebase with no change to 10.0%/52.49% authorized ROE/equity ratio. The increase is for recovery of fixed generation/transmission charges, fuel and purchased power, ratebase investment, and environmental remediation from manufactured gas.
  - On Dec 3, the PSCW approved an electric/gas rate increase of \$7.6M/\$4.2M, somewhat below the Oct Staff recommendation of \$10.4M/\$3M, but based on the same Staff ROE of 10% and equity ratio of 52.5%. NSP-WI's had requested a \$27M electric and \$6M gas rate increase based on a 10.2% ROE and 50.59% equity on \$1.2B electric ratebase and \$114M gas ratebase. New rates are effective from January 1, 2016 and are based on a 2016 test year.
- **New Mexico 2015 Electric ratecase refiled; appeal to Supreme Court was rejected against NMPRC's dismissal of rate filed in June 2015.** In Oct 2015, SPS filed a new \$24.35M electric rate increase with the New Mexico Public Regulation Commission (NMPRC), which includes \$45.4M non fuel base rate increase, offset by a -\$21.1M base fuel decrease. The filing was based on a 10.25% ROE on 53.97% equity for \$734M ratebase on a June 30, 2015 historic test year. Meanwhile, SPS's appeal to the NM Supreme Court was rejected against NMPRC's dismissal of the previous rate filing, filed in June 2015 for a \$31.5M electric rate increase, offset by a -\$30.1M base fuel decrease. The June filing was based on a 10.25% ROE on 53.97% equity for \$777.9M ratebase on a 2016 future test year. A final decision from the NMPRC is expected in 2H16.
- **Colorado gas ratecase final decision on January 27<sup>th</sup> adopted most of the ALJ recommendation along with an \$18.6M increase.** Recall that the company's revised request included a \$108M increase based on a 10.1% ROE on 56% equity and \$1.26B-\$1.36B ratebase. This included a \$40.5M base rate increase for 2015 followed by \$14.6M in 2016 and another \$16.8M in 2017. XEL also requested increases for the Pipeline System Integrity Adjustment rider (PSIA) of \$14.7M in 2016 and \$21.7M in 2017. However, in October the ALJ proposed decision was for a 9.5% ROE on 56.5% equity (no specific revenue

SPS has filed for rehearing of this case

Timing is unclear on resolution; likely 2H 2016

Final decision in Colorado was in-line with the ALJ recommendation

requirement), rejecting the multi-year plan and recommending a historic test year with average ratebase. The ALJ also recommended a 3-year extension of the PSIA. This was marginally better than the June 24<sup>th</sup> Staff recommendation for a -\$6.3M rate decrease based on a 9% ROE and 47.04% equity and the Office of Consumer Counsel (OCC) recommendation for a \$5.8M increase based on a 9% ROE and 52.7% equity. Both staff and OCC opposed the multi-year step increases proposed by XEL for 2016 and 2017, although staff had recommended continuing the PSIA rider through 2017 and OCC recommended terminating it in June 2016.

- **In other Colorado news, we increasingly suspect the state will move to roll back the Net Energy Metering (NEM)** across its various service territories. While controversial, we suspect a new scheme could yet emerge that supports Community Solar over rooftop NEM; Colorado is increasingly emerging alongside Massachusetts as the focal point for Community Solar efforts.
- **XEL continues to advocate for utility scale solar** as more cost effective for consumers than more distributed solutions, including solar rooftop and solar gardens, which require heavy subsidization from non-participants. Most recently, Minnesota limited the size of contiguous solar gardens to 1 MW after some developers attempted to bypass the 1MW max rule with multiple contiguous facilities.

# AES Corp

We look for management to report **\$0.23** adjusted EPS, a slight decline YoY as commodity and F/X headwinds offset much of the gains made elsewhere. We emphasize with few new assets reaching in-service for the relevant period, much of the comparison remains simply capital allocation. **We do not expect a further revision to 2016 EPS guidance following several quarters of continued volatility, with negligible MtM impacts QoQ and intact range of \$0.95-1.05 as best we can tell.** In this sense, we see 1Q results as relatively lower key in terms of update, with discussion more around portfolio turnover rather than overarching views on guidance.

**1Q results will maintain headwinds seen with lower guidance**

**Figure 243: 1Q16E YoY EPS**

AES Earnings Walk		EPS
1Q15A Adjusted EPS		\$0.25
Hydrology - Brazil Recovery		0.00
F/X & Commodities MtM		(0.04)
Capital Allocation - Debt Paydown		0.01
Capital Allocation - Equity Buyback		0.02
Asset Sales		0.01
Tax Rate		(0.01)
1Q16E Adjusted EPS UBSe		\$0.23
1Q16E Consensus		\$0.25
2016E UBSe		1.05
2016E Consensus		1.42
2016 Guidance		0.95-1.05

Source: Company data, Thomson Reuters, UBS estimates

## Updated EPS Projections

We show below our estimates for AES, which have been updated to latest F/X and commodities, slightly higher from our last MtM. With 1Q results, management maintained its 12-16% growth range, biasing towards the upper end of this range, suggesting 2018 is not far off the current outlook from consensus (\$1.33 at the time).

**Figure 244: AES EPS estimates – Dropping estimates modestly**

	2015	2016E	2017E	2018E	2019E	2020E
EPS	1.22	1.05	1.14	1.25	1.57	1.74
EPS Growth %		-14%	9%	10%	25%	11%
Guidance - Low	1.18	0.95	1.06	1.19	1.33	1.49
Guidance - High	1.25	1.05	1.16	1.29	1.44	1.61
Consensus		1.00	1.14	1.29		
Previous EPS	1.21	1.05	1.18	1.36	1.60	

Source: Company data, FactSet, UBS estimates

***For additional context, please refer links to relevant recent reports below:***

[2/29/2016: Doing the Debt Walk](#)

[2/24/2016: Feeling the Full Force of Forex](#)

[12/22/2015: Another Embattled IPP](#)

## Thinking through the Economics of the New assets

We include our initial expectations for the latest growth projects. While the call included a formal decision to move forward with the Masinloc II project (contemplated for many years), the most significant new incremental datapoint included a recently awarded PPA to build out a new 350-MW CCGT in Panama fired via LNG imports. Overall, through 2020, new assets are estimated to contribute an incremental \$0.20 in EPS.

**Figure 245: Growth Projects – \$0.20 in EPS with ~\$900Mn in Equity**

Location	Panama	AES Southland	Philippines
Equity Investment (\$MM)	\$250	\$600	150
Expected Start Date	2019	2020	2019
ROE (%)	13%	13%	13%
NI (\$MM)	\$33	\$78	\$20
Shares Outstanding (UBSe)	635	635	635
EPS (\$)	\$0.05	\$0.12	\$0.03

Source: Company reports, UBS estimates

## But more asset sales are coming nonetheless

Management remains committed to further asset sales, with ~half of the 2016 \$400 Mn buyback contemplated from ~\$180 Mn of asset sale proceeds. Generically, management has guided towards \$250-300 Mn/yr in asset sales, seeing ~\$1 Bn in total proceeds through 2018. We emphasize its modestly sized Elsa gas plant in the Netherlands has a call-option with Dow, which is expected to be executed in 2017.

## How to think about Utilities vs. IPP Assets?

Management has been quite clear in indicating it prefers exposure to contracted power over utilities in emerging markets. As such, it has expressed clearly its intent to sell down its AES Sul subsidiary as part of its ongoing restructuring. Further, the question is how it will structure its AES Brasiliana subsidiary. Management has repeatedly stated it is too correlated to the Bovespa in its parent equity, and as such could be poised to divest more than AES Sul as part of any transaction.

That said, the question also remains how and if it would choose to re-lever its AES Tiete subsidiary. We note management has indicated it has capacity however has held off in recent times from executing on this latitude. While management is committed to contracted power – and hence has suggested this entirely debt fuelled acquisition would be quite accretive – it would still likely expand its power footprint in a country where it is attempting to reduce its beta. A re-leveraging of Tiete had been a principal positive catalyst for shares in 1H16 – and could limit further improvement from a fundamental perspective.

## Updated EPS Projections

We show below our estimates for AES, which have been updated to latest F/X and commodities, slightly higher from our last MtM. With 1Q results, management maintained its 12-16% growth range guidance, biasing towards the upper end of this range, suggesting 2018 is not far off the current outlook from consensus (\$1.33 at the time).

**Figure 246: AES EPS estimates – Dropping estimates modestly**

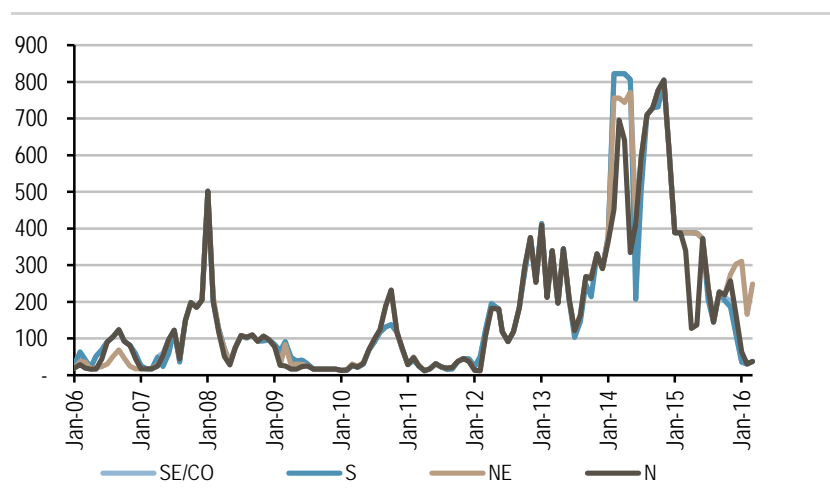
	2015	2016E	2017E	2018E	2019E	2020E
EPS	1.22	1.05	1.14	1.26	1.57	1.75
EPS Growth %		-14%	9%	10%	25%	11%
Guidance - Low	1.18	0.95	1.06	1.19	1.33	1.49
Guidance - High	1.25	1.05	1.16	1.29	1.44	1.61
Consensus		1.00	1.14	1.29		
Previous EPS	1.21	1.05	1.18	1.36	1.60	

Source: Company data, FactSet, UBS estimates

## Brazil Prices Returning to Nominal Levels

We emphasize power prices have returned to modest levels.

**Figure 247: Brazilian spot market prices remain volatile (R\$/MWh, in real terms, Sep. 2015 prices)**

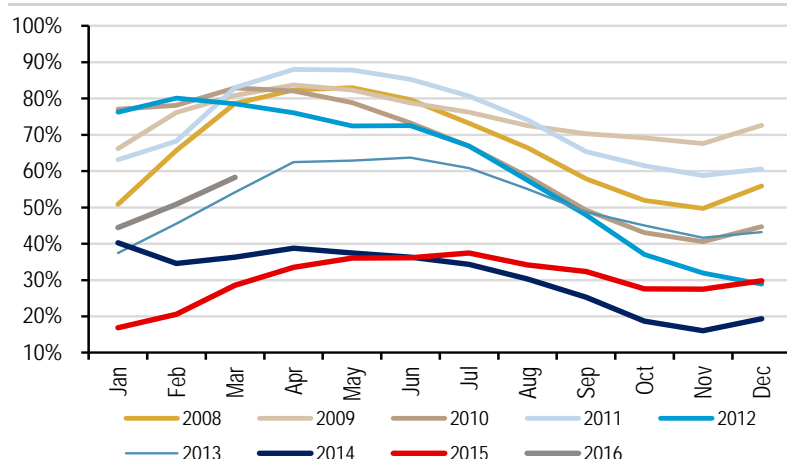


Source: CCEE, UBS

## Hydrology Update

Reservoir levels today are better than one year ago but this is due to high level of dispatch of thermoelectricity plants.

**Figure 248: Brazil hydrology: reservoir level data**



Source: ONS, UBS Brazilian utility team estimates

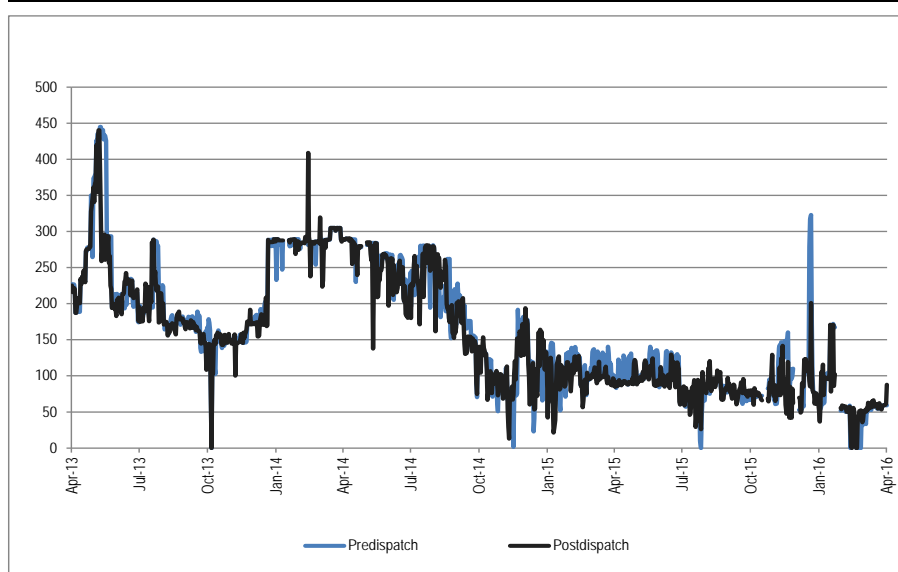
### Is AES too correlated to Brazil?

We see a clear desire from management to reduce AES' correlation to the Brazilian Bovespa, given many investors see the company as too tightly correlated to the wider Brazilian market despite its minority stake in multiple businesses (Tiete/Electropaulo).

### Panamanian Hydro Disclosures

Following significant scrutiny in 2013 of hydro levels across Central America, we include recent spot prices following the significant drought conditions experienced recently. Hydrology in Panama has also improved significantly following a severe drought in 2013 similar to others in South America.

**Figure 249: Panama Spot Prices – Pre/Post-Dispatch (Generation MWh per Unit System) – Back at the lows**



Source: Company reports

## Tracking F/X & Commodity Moves

### Where has 2016 guidance trended since it was launched?

We show below the annualized 2016 impact, with limited deviations from management's current assumptions to derive its \$0.95-1.05 range.

**Figure 250: Annualized 2016 EPS impact using delta b/w management's 2016 average rates assumption vs. actuals**

FX Exposure				Kazakhstan Tenge	Colombian Peso		
	Argentine Peso	Brazilian Real	Euro	British Pound			
Average Rate assumed for 2016							
as on 12/31/2015	15.90	4.23	0.92	0.68	386.30 3261.00		
Rate as on 4/11/2016	14.52	3.49	0.88	0.70	336.70 3053.87		
% change	-8.7%	-17.5%	-4.5%	3.3%	-12.8% -6.4%		
Correlation	-ve	-ve	-ve	-ve	-ve		
Assumed sensitivity	0.005	0.005	0.005	0.005	0.005 0.005		
2016 EPS impact	0.0043	0.0087	0.0022	-0.0016	0.0064 0.0032		
2016 EPS Sensitivity	0.44%	0.88%	0.22%	-0.17%	0.65% 0.32%		
Commodity Exposure							
	NYMEX Coal	Rotterdam Coal	WTI Crude	Brent Crude	Henry Hub Nat Gas	UK NBP Nat Gas	PJM AD Hub
Average Rate assumed for 2016							
as on 12/31/2015	45	44	41	41	2.50	0.47	32
Rate as on 4/11/2016	43.6	44.3	39.5	41.6	1.9	0.4	31
% change	-3.0%	0.7%	-3.8%	1.5%	-22.8%	-12.8%	-4.2%
Weighting	52%	48%	25%	75%	75%	25%	100%
Correlation		-ve		+ve		+ve	+ve
Assumed sensitivity	0.010	0.010	0.005	0.005	0.005	0.005	0.025
2016 EPS impact		0.0013		0.0001		-0.0101	-0.0105
2016 EPS Sensitivity		0.13%		0.01%		-1.02%	-1.06%
MtM							
Total MtM Impact to EPS	MtM currency impact	commodity impact	Total New Impact (EPS)	Total New Impact (\$ M n's)	% Change in EPS		
2016 EPS UBSe	0.0233	-0.0193	0.00	4	0.4%		

Source: Company reports, FactSet, UBS estimates, Bloomberg

## Currency Exposures: Finding a Bottom

We include charts of currency affecting AES. Across all major regions with exposure for AES we see a reversal of the USD appreciation seen in recent periods. We flag most currencies remain a headwind for the company, with further inflation of late in the Kazakhstan Tenge and Argentine Peso. Meanwhile YoY comparisons for the Colombian Peso, Brazilian Real, Euro, and Pound all remain problematic.

**Figure 251: F/X Rate for USD / Brazilian Real**



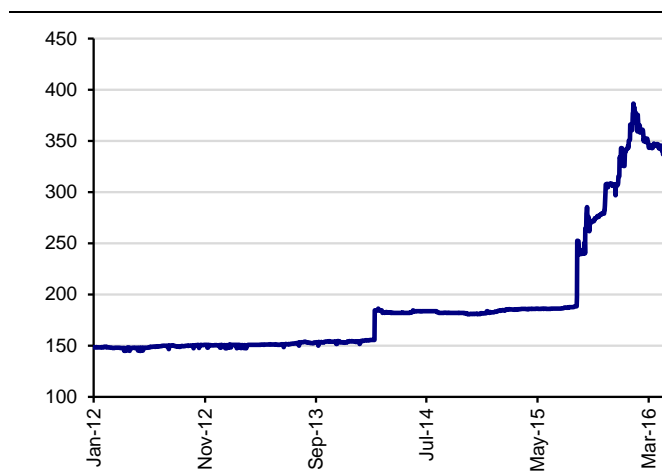
Source: FactSet

**Figure 252: F/X Rate for USD / Euro**



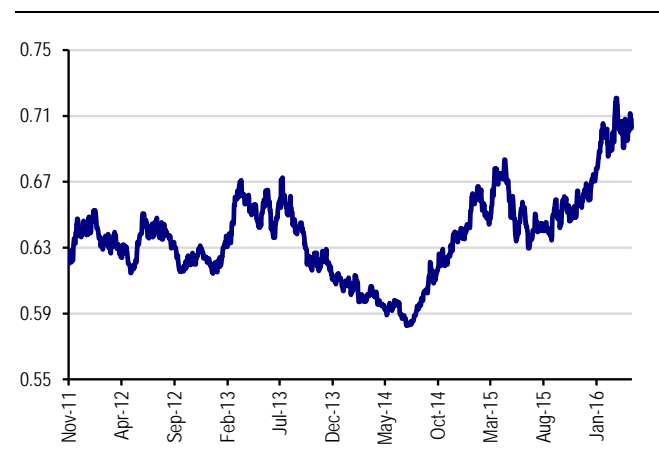
Source: FactSet

**Figure 253: US Dollar per Kazakhstan Tenge**



Source: FactSet

**Figure 254: US Dollar per GBP**



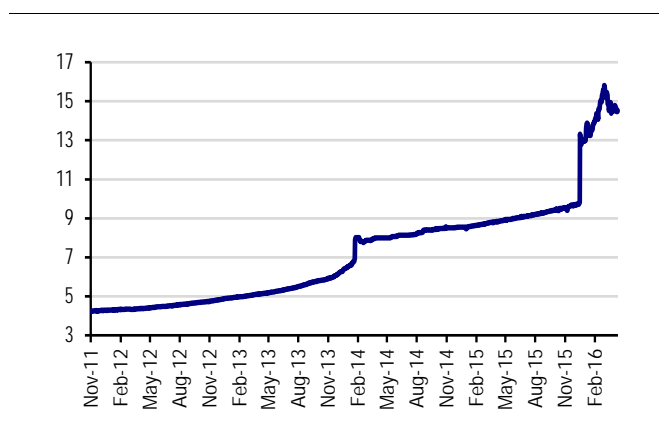
Source: FactSet

**Figure 255: US Dollar per Colombian Peso**



Source: FactSet

**Figure 256: F/X Rate for USD / Argentine Peso**



Source: FactSet

## Underlying International Commodity Performance

International coal prices have been declining since the beginning of the year and domestic coal prices. We see pressure on both commodities as limiting

improvement in power markets for coal-heavy regions given the high inventory balances after two quarters of materially milder weather.

**Figure 257: Rotterdam Coal (\$/ton), International Coal Proxy**



Source: FactSet

**Figure 258: NYMEX CAPP Coal (\$/ton), Domestic Coal Proxy**



Source: FactSet

## Comparing the Forward Gas Months: US vs. Europe

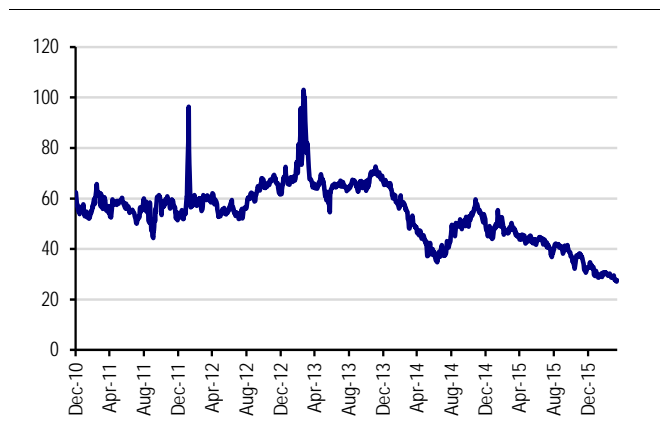
Henry Hub natural gas rose from August '13 lows of ~\$3.23/MMBtu to a high of ~\$6.15 on February 19<sup>th</sup> 2014. They have been declining steadily since then and are trading ~\$2.3 as of now; down -19% over 2015. Meanwhile, European gas prices have experienced decline of -33% over 2015. We see reversal of coal to gas switching at prices *at or above* \$4.50/MMBtu as meaningfully capping upside to gas demand over the intermediate term.

**Figure 259: US Natural Gas (Hub), \$/MMBtu Front Month**



Source: FactSet

**Figure 260: European Natural Gas (NBP), pence/therm**

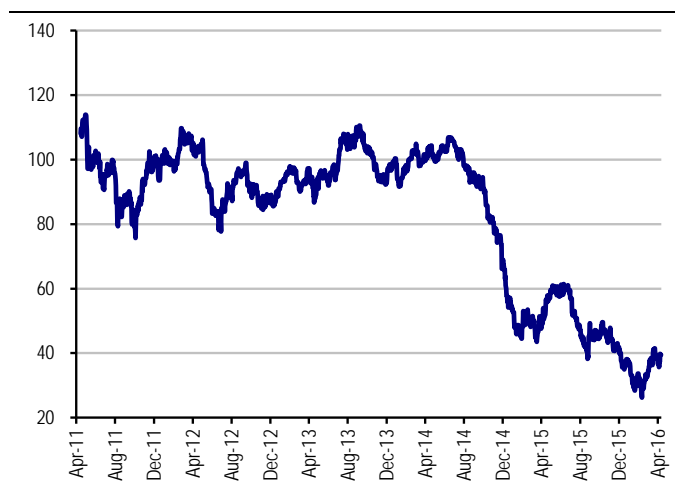


Source: Bloomberg

## Oil Prices: US vs. Europe

Meanwhile, domestic and international oil both appear to have found bottoms. Both WTI and Brent are trading at the sub \$35 level at the moment; and were down -30% and -35% respectively over 2015. We note here that according to management estimates for 2016, a 10% increase in WTI or Brent will result ~\$0.01 increase in 2016 EPS (note they are positively correlated).

**Figure 261: Crude Oil (WTI), \$/Bbl**



Source: FactSet

**Figure 262: Crude Oil (IPE Brent), \$/Bbl**



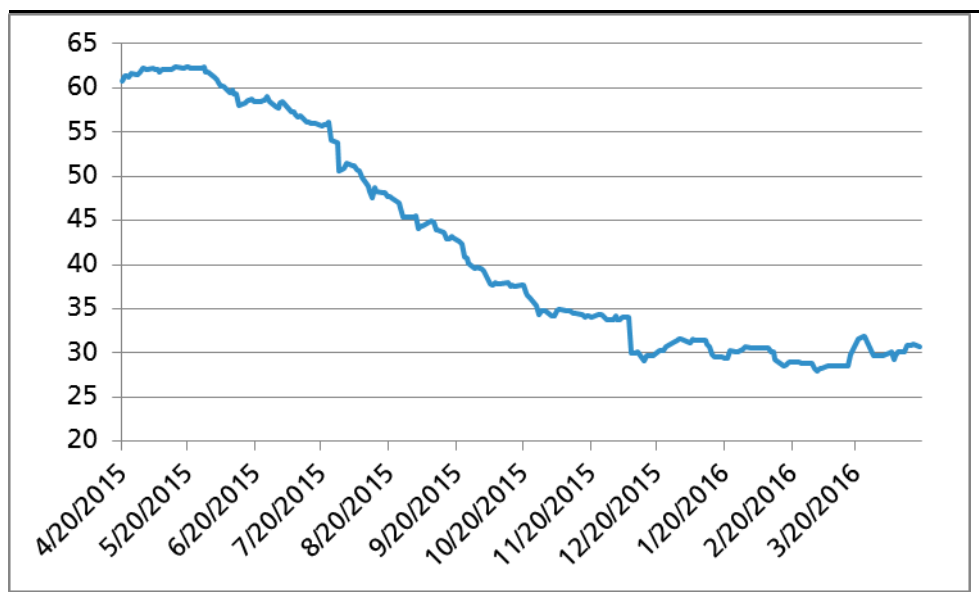
Source: FactSet

## EFH (Unrated)

### EFH Debt: Continues Gap Down

We include EFH bank debt below – we think this is relevant given similarities to NRG equity. We emphasize as the bankruptcy continues to edge towards plan confirmation, executives involved continue to express confidence on path back towards IPO of remaining entity (assuming sale of regulated assets), leaving only the generation and retail business under Luminant. The bank debt below is tied to the TCEH business. The trend below (effectively reflecting unlevered asset value) is similar to equity valuation trends elsewhere in the IPP sector.

**Figure 263: EFH Latest Bank Debt (Extended 2017 Term Loan)**



Source: Bloomberg

### But what about retail trends overall?

TXU Energy has not provided an update on its projections since its last 8k last August. We expect all retailers to continue to post higher retail margins as wholesale prices decline; we see these two businesses as complementary. Such an outcome has been quite clear at least with the public results of NRG.

Figure 264: Updated EFH MtM projections using company disclosed of financials 8k

EFH Corp Mini-Model Projections using Mgmt Projections and Updating using MtM Commodities						
	2015	2016	2017	2018	2019	2020
<b>TCEH Consolidated Adjusted EBITDA (from 10-15-13 8k), using old commodity</b>	1,939	1,858	1,803			
<b>TCEH Consolidated Adjusted EBITDA (from 8-10-15 8k), using 12/31/14 Commodities</b>	1,565	1,316	1,489	1,673	2,021	1,976
Subtract: TXU Energy (using 2012 Guidance midpt & projected YoY changes)	589	559	544	529	514	499
<b>Implied Generation (Luminant) EBITDA</b>	976	757	945	1,144	1,507	1,477
Hedge Value	0	0	0	0	0	0
<b>Implied Open EBITDA Generation (Luminant) , using 8k</b>	976	757	945	1,144	1,507	1,477
EEI Guidance Open EBITDA Guidance (Midpoint)						
O&M	875	923	956	960	961	1,011
D&A	1,330	506	270	272	278	286
SG&A	605	648	658	672	650	641
<b>Implied Open Generation GM</b>	1,851	1,680	1,901	2,104	2,468	2,488
Implied Open Revenue	2,751	2,718	2,949	3,140	3,514	3,544
<b>Expected Generation TWh (Mgmt Projection from from 4-29-14 8k)</b>	61	66	66	65	65	65
Nuclear TWh (UBSe)	19	18	18	18	18	18
Coal TWh (Implied)	42	48	48	47	47	47
Total Coal Capacity (MW), Monticello 1&2 for Summer-Only (33%)	7,303					
Implied Capacity Factor on Coal (%)	80%					
Open Revenues (Est. Using Premium to ERCOT Prices)	1,910	2,288	2,534	2,685	2,971	3,040
ERCOT-North (ATC), as of 12/31/2014 (from 8-10-15 8k)	30.40	33.98	38.01	41.31	45.71	46.77
Houston Shipping Channel Gas, as of 12/31/2014 (from 8-10-15 8k)	3.01	3.51	3.85	4.04	4.20	4.30
ERCOT-North Premium (% over ATC)	3%	2%	1%	0%	0%	0%
Realized Power Price (\$/MWh)	31.31	34.66	38.39	41.31	45.71	46.77
Nuclear Dispatch Costs (\$/MWh)	7	7	7	7	7	7
Coal Dispatch Costs (\$/MWh)	21.42	21.63	21.84	22.05	22.26	22.47
Implied Delivered PRB Price (\$/t), UBSe	40	41	42	43	44	45
Implied Delivery Price (\$/t), UBSe	29	30	31	32	33	34
Fuel Cost (Only Coal/Nuclear Fuel Excl from Adj. EBITDA)	900	1,038	1,048	1,036	1,046	1,056
<b>Baseload-Only Gross Margin (UBSe), as of Feb 1st</b>	1,010	1,249	1,485	1,649	1,925	1,984
<b>Asset Management, using this as Plug to Mgmt</b>	841	431	416	455	543	504
<b>Open Luminant EBITDA (UBSe)</b>	135	326	529	689	964	973
Add : Hedges (As disclosed by Mgmt) - 4/29/14 8K	-	-	-	-	-	-
<b>Hedged Luminant (Generation) EBITDA (UBSe), as of Feb 1st</b>	976	757	529	689	964	973
Add : TXU Energy, Retail Business EBITDA (from above)	589	559	544	529	514	499
<b>Hedged TCEH EBITDA (UBSe), as of Feb 1st 8k</b>	1,565	1,316	1,073	1,218	1,478	1,472
Implied All-in Fuel, O&M, SG&A Costs (\$/MWh)	29	30	30	31	31	32
Guidance						
ERCOT-North (ATC) - MtM	31.13	24.14	27.30	27.86	28.92	29.42
<b>Reflecting the Latest Commodity Shifts</b>						
ERCOT-North (ATC) - MtM Improvement/(Declines), \$/MWh	0.73	(9.84)	(10.71)	(13.45)	(16.79)	(17.35)
Volumes	61	66	66	65	65	65
Change in Hedge Value vs. Forward Curves	45	(650)	(707)	(874)	(1,091)	(1,128)
<b>Hedged TCEH EBITDA (Mgmt Projections), using latest MtM</b>	1,610	666	782	799	930	848
Nuclear Fuel (Not Included in Mgmt's EBITDA), UBSe	(147)	(81)	(86)	(161)	(90)	(100)
Maintenance/Enviro Capex (Plug from Nuclear Fuel vs. Mgmt Total)	(476)	(329)	(268)	(303)	(329)	(246)
<b>TCEH FCF (Pre-Other CF Items)</b>	987	256	428	335	511	502
Working Capital	(16)	(26)	(10)	(16)	(16)	(16)
<b>TCEH FCF (Pre-Interest), using Mgmt Projections &amp; MtM</b>	971	230	418	319	495	486
<b>FCF Yield on Bank Debt</b>	5.4%	1.4%	2.3%	1.8%	2.8%	2.7%

Source: Company filings, UBS estimates

# Calpine Corporation

## Anticipating Weak 1Q16 Results

### 1Q expectations should be a bit weak

We look for CPN to post results shy of the Street consensus, as the YOY improvement \$338Mn in EBITDA amounts to just ~\$20Mn, principally driven by contributions from new assets YoY. Aggregate hedge positions appear to suggest flat to some degradation in YoY results, coupled with a reduction in expected dispatch given improvement in Western hydrology. We emphasize the turnaround in drought conditions out West has put downward pressure on results. Following record 27TWh in 1Q last year, a near record, we see potential for erosion based on further degradation in CCGT output of the Western portfolio (~1-2TWh possible judging from historicals). Further, contributions from the inaugural quarter of Granite Ridge during a particularly mild Northeast quarter suggests contributions closer to ~\$10 Mn seemingly at best.

### Capital allocation refocus

With 4Q results, Calpine reaffirmed its 2016E adjusted FCF guidance of \$710-\$865Mn (\$788Mn UBS estimates) which excludes ~\$800Mn growth capital for the Granite Ridge acquisition and York 2 which essentially erases positive organic free cash flow for the year. Management presents its 2016E available capital for allocation of \$1,750Mn which includes \$906Mn of 12/31/14 unrestricted cash on hand, \$166Mn of proceeds from the pending Osprey sale that will not be received until January 2017, and 2016E FCF (\$782Mn midpoint), less \$100Mn.

### Debt and equity de-linked?

The debt remains largely intact through the credit crisis in the energy sector of late, largely trading near par, preventing shares from being bought back at a discount. We continue to expect most debt paydown to be oriented towards 2H16 regardless given timing of cash flow.

### Valuation: Maintaining \$17 price target

We are maintaining our price target (based on a 2018E sum-of-the-parts methodology) at \$17/sh with little change in our 2017 EBITDA estimates (our EPS estimates rise ~9-11% for 2016-17 on marking-to-market underlying commodities). We continue to see shares as trading principally as a function of the credit cycle in high-yield energy given its higher leverage.

### Equities

Americas

Electric Utilities

12-month rating

Buy

12m price target

US\$17.00

Price

US\$15.73

RIC: CPN.N BBG: CPN US

### Trading data and key metrics

<b>52-wk range</b>	US\$22.63-11.80
<b>Market cap.</b>	US\$5.55bn
<b>Shares o/s</b>	353m (COM)
<b>Free float</b>	70%
<b>Avg. daily volume ('000)</b>	1,051
<b>Avg. daily value (m)</b>	US\$14.8
<b>Common s/h equity (12/16E)</b>	US\$3.02bn
<b>P/BV (12/16E)</b>	1.7x
<b>Net debt / EBITDA (12/16E)</b>	6.1x

### EPS (UBS, diluted) (US\$)

	12/16E			
	From	To	% ch	Cons.
<b>Q1E</b>	0.13	0.11	-17	(0.11)
<b>Q2E</b>	0.09	0.08	-4	0.05
<b>Q3E</b>	0.93	0.93	NM	0.77
<b>Q4E</b>	(0.66)	(0.58)	NM	(0.20)
<b>12/16E</b>	0.54	0.60	11	0.62
<b>12/17E</b>	1.32	1.43	9	1.04
<b>12/18E</b>	1.61	1.63	1	1.32

Julien Dumoulin-Smith

Analyst

julien.dumoulin-smith@ubs.com

+1-212-713 9848

Michael Weinstein

Associate Analyst

michael.weinstein@ubs.com

+1-212-713 3182

Paul Zimbardo

Associate Analyst

paul.zimbardo@ubs.com

+1-212-713 1033

Highlights (US\$m)	12/13	12/14	12/15	12/16E	12/17E	12/18E	12/19E	12/20E
<b>Revenues</b>	6,301	8,030	6,472	8,556	8,407	8,450	8,248	8,297
<b>EBIT (UBS)</b>	997	1,112	1,070	978	1,295	1,331	1,249	1,227
<b>Net earnings (UBS)</b>	266	401	478	199	421	415	339	321
<b>EPS (UBS, diluted) (US\$)</b>	0.60	0.98	1.31	0.60	1.43	1.63	1.56	1.80
<b>DPS (US\$)</b>	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
<b>Net (debt) / cash</b>	(10,171)	(10,565)	(11,183)	(11,763)	(11,650)	(11,525)	(11,508)	(11,525)
Profitability/valuation	12/13	12/14	12/15	12/16E	12/17E	12/18E	12/19E	12/20E
<b>EBIT margin %</b>	15.8	13.8	16.5	11.4	15.4	15.8	15.1	14.8
<b>ROIC (EBIT) %</b>	7.7	8.5	8.3	7.6	10.0	10.4	9.9	9.9
<b>EV/EBITDA (core) x</b>	9.8	9.0	7.4	8.0	7.0	6.9	7.2	7.3
<b>P/E (UBS, diluted) x</b>	33.0	22.3	14.0	26.3	11.0	9.7	10.1	8.7
<b>Equity FCF (UBS) yield %</b>	(0.3)	3.9	4.3	6.2	11.1	11.2	9.3	8.7
<b>Net dividend yield %</b>	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Source: Company accounts, Thomson Reuters, UBS estimates. Metrics marked as (UBS) have had analyst adjustments applied. Valuations: based on an average share price that year, (E): based on a share price of US\$15.73 on 19 Apr 2016 19:37 EDT

# Dynegy, Inc.

## IPH Restructuring in the Spotlight

### Look for meaningful improvement YoY, ahead of Street

We look for management to post results modestly ahead of Street expectations. We flag 1Q estimates should benefit substantially from continued YoY benefits from the close of the ECP & Duke portfolios, while the balance of the portfolio should continue to see YoY lower trends as both hedges and mild weather reduce expectations.

### Addressing IPH remains the top priority for this year

Given its recent statements, we see management as keenly focused on addressing the IPH portfolio ahead of any maturities. Following relatively negative MISO capacity print, we think management is likely to elaborate not only on further retirements (presumably Newton gives its higher cost structure among the Illinois coal portfolio) but also on prospects for the segment more broadly. We expect management to discuss an exchange or tender for the \$825 Mn in outstanding debt at this subsidiary (trading at ~30-40c of late, or ~\$290 Mn in market value).

### Looking hard at California still to divest

Management continues to evaluate options around a contemplated divestment of its West Coast portfolio. We see the bulk of the value as accruing to the portfolio via its Moss Landing CCGT, with its remaining assets (Morro, Oakland, and Moss 6&7 as all site value). We expect Moss 6&7 to be retired at year-end at the conclusion of its existing capacity contract (with just one year left on its operating life due to Once-Through-Cooling limitations anyways).

### Valuation: Maintaining \$21 price target

Our valuation continues to be based on a 2018E sum-of-the-parts methodology. The focus will be on the IPH subsidiary and to what extent management could provide value to bondholders for any forthcoming exchange to execute on a deal. For example, market value of debt against the *total* IPH equity would imply ~\$1/sh without adjusting for assets *not* in the ring-fence).

### Equities

Americas  
Electric Utilities

**12-month rating** **Buy**

**12m price target** **US\$21.00**

**Price** **US\$17.05**

**RIC:** DYN.N **BBG:** DYN US

### Trading data and key metrics

<b>52-wk range</b>	US\$34.16-7.43
<b>Market cap.</b>	US\$1.71bn
<b>Shares o/s</b>	100m (COM)
<b>Free float</b>	100%
<b>Avg. daily volume ('000)</b>	894
<b>Avg. daily value (m)</b>	US\$10.4
<b>Common s/h equity (12/16E)</b>	US\$2.99bn
<b>P/BV (12/16E)</b>	0.7x
<b>Net debt / EBITDA (12/16E)</b>	5.7x

### EPS (UBS, diluted) (US\$)

	12/16E			
	From	To	% ch	Cons.
<b>Q1E</b>	-	0.21	-	(0.54)
<b>Q2E</b>	-	0.11	-	(0.50)
<b>Q3E</b>	-	0.68	-	0.45
<b>Q4E</b>	-	0.10	-	(0.51)
<b>12/16E</b>	0.91	1.08	18	(1.03)
<b>12/17E</b>	0.66	0.47	-28	(1.02)
<b>12/18E</b>	2.31	2.19	-5	0.48

Michael Weinstein

Associate Analyst

michael.weinstein@ubs.com

+1-212-713 3182

Paul Zimbardo

Associate Analyst

paul.zimbardo@ubs.com

+1-212-713 1033

Jeremiah Booream

Associate Analyst

jeremiah.booream@ubs.com

+1-212-713 4105

Highlights (US\$m)	12/13	12/14	12/15	12/16E	12/17E	12/18E	12/19E	12/20E
<b>Revenues</b>	1,466	2,497	3,870	5,106	4,993	5,249	5,022	5,027
<b>EBIT (UBS)</b>	(309)	(51)	218	729	652	958	894	870
<b>Net earnings (UBS)</b>	(359)	(278)	127	134	59	272	234	219
<b>EPS (UBS, diluted) (US\$)</b>	(3.59)	(2.78)	1.27	1.08	0.47	2.19	1.88	1.76
<b>DPS (US\$)</b>	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
<b>Net (debt) / cash</b>	(1,149)	(6,226)	(6,784)	(6,424)	(6,153)	(5,860)	(5,633)	(5,432)
Profitability/valuation	12/13	12/14	12/15	12/16E	12/17E	12/18E	12/19E	12/20E
<b>EBIT margin %</b>	-21.1	-2.0	5.6	14.3	13.1	18.3	17.8	17.3
<b>ROIC (EBIT) %</b>	(8.9)	(0.7)	2.2	7.5	6.8	10.2	9.5	9.2
<b>EV/EBITDA (core) x</b>	14.9	12.6	10.9	7.5	8.1	6.3	6.6	6.7
<b>P/E (UBS, diluted) x</b>	(5.9)	(10.2)	20.4	15.8	36.1	7.8	9.1	9.7
<b>Equity FCF (UBS) yield %</b>	6.9	6.0	(2.2)	24.8	15.9	17.2	13.3	11.8
<b>Net dividend yield %</b>	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Source: Company accounts, Thomson Reuters, UBS estimates. Metrics marked as (UBS) have had analyst adjustments applied. Valuations: based on an average share price that year, (E): based on a share price of US\$17.05 on 19 Apr 2016 19:37 EDT

# NRG Energy Inc.

## GenOn Solution Coming in 2016?

### GenOn: Seeking a resolution, slow and steady

GenOn debt restructuring and ultimate solution could materialize later this year but we don't expect immediate resolution and see management potentially pursuing tenders at discount to par alongside expected further asset sales. Further, we don't expect the parent to make any concessions that put debt ratios (4.25X corp debt max) at risk, given shaky capital markets and risk of credit review if metrics deteriorate. While new effective allocation of G&A expense to the segment is unclear, favorable resolution to GenOn could drive meaningful share appreciation, in our view.

### Why do we think Home Solar JV is more likely than a sale?

Public valuations for residential solar companies have declined sharply in 2016 (SolarCity, Sunrun, and Vivint Solar are down an average of ~50% YTD) as the macro environment for residential solar has deteriorated with increasing financing costs and competition. A partnership also would allow NRG Energy to retain value from its retail assets: in this scenario NRG Energy would be the 'origination engine' for potential parties interested in residential solar. In the interim, the company is paring back expansion plans (recently shut down North Carolina operations) and should have a resolution in the very near term (recently reaffirmed final resolution of Home Solar and EVgo in 2Q16). We see this becoming a positive source of cash contribution (albeit slight) from a drag today, resolving one of the wider 'overhangs' on the stock today.

### And what happens to NYLD overall?

We think the most likely outcome for NYLD is largely status quo in relation to NRG. Potential roll up would require significant changes/reckoning on the tax equity, land financing, and other fronts, which would make it very difficult. We believe NYLD continues to be a source of value for NRG in the current form and NRG management is likely more focused on corporate deleveraging.

### Valuation: Raising SOTP-based PT to \$16 from \$14

Our changes reflect entirely the shifts in commodity MtM rather than any meaningful underlying shifts in assumptions. We flag among the key assumptions we have made is the fact that GenOn is non-recourse and hence removed from our valuation. This is consistent with our treatment of DYN's IPH subsidiary now of late as well.

## Equities

Americas  
Electric Utilities

**12-month rating** **Buy**

**12m price target** **US\$16.00**  
*Prior: US\$14.00*

**Price** **US\$14.31**

**RIC:** NRG.N **BBG:** NRG US

### Trading data and key metrics

<b>52-wk range</b>	US\$26.43-8.98
<b>Market cap.</b>	US\$4.81bn
<b>Shares o/s</b>	336m (COM)
<b>Free float</b>	100%
<b>Avg. daily volume ('000)</b>	1,613
<b>Avg. daily value (m)</b>	US\$19.1
<b>Common s/h equity (12/16E)</b>	US\$5.73bn
<b>P/BV (12/16E)</b>	0.8x
<b>Net debt / EBITDA (12/16E)</b>	5.6x

### EPS (UBS, diluted) (US\$)

	12/16E			
	From	To	% ch	Cons.
<b>Q1E</b>	0.24	0.24	0	(0.03)
<b>Q2E</b>	0.60	0.60	0	0.43
<b>Q3E</b>	0.73	0.73	0	0.65
<b>Q4E</b>	(0.38)	(0.38)	NM	(0.36)
<b>12/16E</b>	1.18	1.18	0	0.74
<b>12/17E</b>	0.88	0.99	12	(0.17)
<b>12/18E</b>	1.90	2.06	8	1.03

Michael Weinstein

Associate Analyst

michael.weinstein@ubs.com

+1-212-713 3182

Paul Zimbardo

Associate Analyst

paul.zimbardo@ubs.com

+1-212-713 1033

Highlights (US\$m)	12/13	12/14	12/15	12/16E	12/17E	12/18E	12/19E	12/20E
<b>Revenues</b>	11,295	15,868	14,674	15,258	15,153	15,377	15,521	15,513
<b>EBIT (UBS)</b>	1,380	1,605	1,831	2,183	2,085	2,270	2,398	2,370
<b>Net earnings (UBS)</b>	274	262	(1,487)	373	304	616	829	839
<b>EPS (UBS, diluted) (US\$)</b>	0.85	0.78	(4.43)	1.18	0.99	2.06	2.84	2.95
<b>DPS (US\$)</b>	0.48	0.54	0.54	0.24	0.12	0.12	0.12	0.12
<b>Net (debt) / cash</b>	(14,812)	(18,568)	(18,277)	(17,592)	(16,608)	(14,761)	(12,839)	(10,872)
Profitability/valuation	12/13	12/14	12/15	12/16E	12/17E	12/18E	12/19E	12/20E
<b>EBIT margin %</b>	12.2	10.1	12.5	14.3	13.8	14.8	15.4	15.3
<b>ROIC (EBIT) %</b>	7.4	7.9	9.5	12.6	12.5	14.5	16.7	18.1
<b>EV/EBITDA (core) x</b>	6.3	6.2	5.5	5.1	5.0	4.1	3.4	2.8
<b>P/E (UBS, diluted) x</b>	31.3	39.6	(4.7)	12.1	14.5	7.0	5.0	4.8
<b>Equity FCF (UBS) yield %</b>	(9.1)	5.9	0.4	(0.9)	6.7	24.6	26.1	27.1
<b>Net dividend yield %</b>	1.8	1.7	2.6	1.6	0.8	0.8	0.8	0.8

Source: Company accounts, Thomson Reuters, UBS estimates. Metrics marked as (UBS) have had analyst adjustments applied. Valuations: based on an average share price that year, (E): based on a share price of US\$14.31 on 19 Apr 2016 19:37 EDT

# Talen Energy Corp

## Updating Thoughts Around Potential LBO News

### LBO scenario appears increasingly plausible

Based on multiple (Bloomberg, DealReporter) articles over the last few weeks, we believe a transaction involving private equity is plausible for a variety of reasons: 1) Riverstone (one potential reported suitor) already owns 35% of TLN. 2) Senior management recently completed severance agreements. 3) Limited change of control provisions on long-term debt. 4) Room for optimization in capital structure. 5) Private equity has pursued similar deals in the past.

### How does a potential LBO shift the capital allocation plans?

Previously management has said that it will provide an update on its capital allocation plans when it received the cash from the hydro asset sale (occurred on April 1<sup>st</sup>) and made a decision on the gas-firing addition to Montour (1H16) so the company should have visibility here. If the reports of a potential LBO are valid, we believe any acquirer would likely prefer transacting before Talen begins repurchasing debt to maximize the set of opportunities. For example, as mentioned Talen has indicated that it could pursue adding secured debt to assets to free-up capital for tender unsecured corporate debt. If this plan is executed with further restrictions placed on debt, this could create value for Talen today, but it would reduce flexibility in the capital structure. While a private equity player could buy the assets for the 'cash on the balance sheet', the reality is the investment to buy the company is a real one as the cash cannot be 'taken' from the company but rather deployed to fund further growth or debt restructuring avenues.

### Adjusting EBITDA estimates

Our revised EBITDA estimates for 2016/2017/2018 are \$742 Mn / \$591 Mn / \$622 Mn / \$565 Mn vs. \$751 Mn / \$589 Mn / \$599 Mn / \$563 Mn previously, compared to consensus estimates of \$745 Mn / \$723 Mn / \$659 Mn (no 2019 consensus estimates). We now include the Brunner Island conversion (\$20-\$35Mn estimate) and the impact from the latest forward curves. We continue to include the drag from Harquahala (\$5-10Mn estimate).

### Valuation: Maintaining \$6 price target

Our valuation remains based on 2018E SOTP.

### Equities

Americas  
Electric Utilities

12-month rating **Neutral**

12m price target **US\$6.00**

Price **US\$12.30**

RIC: TLN.N BBG: TLN US

### Trading data and key metrics

52-wk range	US\$23.48-5.76
Market cap.	US\$1.58bn
Shares o/s	129m (COM)
Free float	100%
Avg. daily volume ('000)	258
Avg. daily value (m)	US\$2.1
Common s/h equity (12/16E)	US\$6.08bn
P/BV (12/16E)	0.3x
Net debt / EBITDA (12/16E)	6.6x

### EPS (UBS, diluted) (US\$)

	12/16E			
	From	To	% ch	Cons.
Q1E	-	(0.32)	-	0.31
Q2E	-	(0.82)	-	0.06
Q3E	-	0.94	-	0.83
Q4E	-	0.86	-	(0.51)
12/16E	0.51	0.67	32	0.65
12/17E	(0.95)	(0.93)	NM	0.27
12/18E	(0.80)	(0.63)	NM	(0.06)

Michael Weinstein

Associate Analyst

michael.weinstein@ubs.com

+1-212-713 3182

Paul Zimbardo

Associate Analyst

paul.zimbardo@ubs.com

+1-212-713 1033

Highlights (US\$m)	-	12/14	12/15	12/16E	12/17E	12/18E	12/19E	12/20E
Revenues	-	4,274	4,481	3,906	3,579	3,654	3,614	3,656
EBIT (UBS)	-	441	500	234	82	113	59	72
Net earnings (UBS)	-	139	262	87	(122)	(84)	(138)	(130)
EPS (UBS, diluted) (US\$)	-	1.08	2.04	0.67	(0.93)	(0.63)	(1.04)	(0.98)
DPS (US\$)	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net (debt) / cash	-	(3,931)	(4,705)	(4,908)	(5,013)	(5,183)	(5,383)	(5,530)
Profitability/valuation	-	12/14	12/15	12/16E	12/17E	12/18E	12/19E	12/20E
EBIT margin %	-	10.3	11.2	6.0	2.3	3.1	1.6	2.0
ROIC (EBIT) %	-	-	5.2	2.2	0.7	1.0	0.5	0.6
EV/EBITDA (core) x	-	-	5.5	7.9	11.0	10.7	12.1	11.8
P/E (UBS, diluted) x	-	-	6.4	18.3	(13.2)	(19.5)	(11.9)	(12.5)
Equity FCF (UBS) yield %	-	-	19.0	83.2	6.3	5.7	3.8	6.5
Net dividend yield %	-	-	0.0	0.0	0.0	0.0	0.0	0.0

Source: Company accounts, Thomson Reuters, UBS estimates. Metrics marked as (UBS) have had analyst adjustments applied. Valuations: based on an average share price that year, (E): based on a share price of US\$12.30 on 19 Apr 2016 19:37 EDT

# ITC Holdings Corp

## What are the Bonus Depreciation Impacts?

### ITC ordered to refund impact of bonus depreciation for 2015

On March 11<sup>th</sup> the FERC ruled partially in favor of Alliant's Interstate Power and Light subsidiary (IPL) in its challenge against ITC's subsidiary (ITC Midwest). Specifically the FERC ruled that ITC did not justify its decision to not elect bonus depreciation in 2015. ITC will recalculate the rates at this subsidiary to simulate the impact of bonus depreciation and issue a refund to customers. Based on IPL's calculation the impact on 2015's revenue requirement was +\$18Mn (\$0.07/sh after-tax). ITC Midwest represents 35-40% of ITC forecasted ratebase.

### FERC does not require ITC to elect bonus depreciation going forward

The FERC ruling only applies to 2015 and is neither retroactive nor automatically applicable to future periods. For prior periods the FERC does not want to intervene in IRS matters as ITC has already filed its taxes to not elect bonus depreciation. For future periods the FERC stated that rates are assumed to be prudent until proved imprudent; therefore, if ITC does not elect bonus depreciation in the future it is open to challenge. For example, if ITC is able to prove a justification for its decision in 2016+ its rates can stand as prudent; however, the rationale provided in 2015 was rejected. If a utility has a valid reason for not electing bonus depreciation (ex. the loss of other tax benefits), that appears to be a sound justification. Absent a change in circumstances for ITC we would expect FERC to again scrutinize ITC if it does not elect bonus depreciation.

### Regulatory approval process expected to begin in June at the latest

The formal acquisition applications will not be filed until the joint venture investment is in place but Fortis stated that it will file the applications "no later than 120-days from the time of the announcement" [February 9] implies that the applications will be made by June 8<sup>th</sup>. The FERC has 180 days to review the transaction indicating a possible decision by early December, consistent with the guided close period of late 2016. Other federal approvals include DOJ and CFIUS in addition to shareholder votes. Fortis expects to require state approval from Illinois, Kansas, Missouri, Oklahoma, and Wisconsin but not Iowa, Michigan, or Minnesota.

### Valuation: Increasing price target to \$46 from \$39 on Fortis recovery

Our valuation is based on Fortis acquisition offer for ITC. When announcing the transaction Fortis disclosed a \$44.90/sh offer price based on \$22.57 USD cash and 0.7520 shares of Fortis per share of ITC Holdings. At the close of the announcement date Fortis closed at \$26.88/sh USD and is now trading at ~\$31/sh USD.

### Equities

Americas  
Electric Utilities

12-month rating **Neutral \***

12m price target **US\$46.00**  
Prior: **US\$39.00**

Price **US\$43.72**

RIC: ITC.N BBG: ITC US

### Trading data and key metrics

52-wk range US\$43.72-31.28  
Market cap. US\$6.80bn  
Shares o/s 156m (COM)  
Free float 99%  
Avg. daily volume ('000) 596  
Avg. daily value (m) US\$24.3  
Common s/h equity (12/16E) US\$1.91bn  
P/BV (12/16E) 3.5x  
Net debt / EBITDA (12/16E) 5.5x

### EPS (UBS, diluted) (US\$)

	12/16E			
	From	To	% ch	Cons.
Q1E	-	0.54	-	0.49
Q2E	-	0.57	-	0.52
Q3E	-	0.56	-	0.54
Q4E	-	0.37	-	0.56
12/16E	2.07	2.05	-1	2.08
12/17E	2.33	2.30	-1	2.22
12/18E	2.55	2.52	-1	2.43

Michael Weinstein

Associate Analyst

michael.weinstein@ubs.com

+1-212-713 3182

Paul Zimbardo

Associate Analyst

paul.zimbardo@ubs.com

+1-212-713 1033

Highlights (US\$m)	12/13	12/14	12/15	12/16E	12/17E	12/18E	12/19E	12/20E
Revenues	941	1,051	1,045	1,229	1,351	1,459	1,522	1,562
EBIT (UBS)	551	621	561	700	783	854	881	886
Net earnings (UBS)	255	302	323	317	357	390	397	391
EPS (UBS, diluted) (US\$)	1.62	1.94	2.07	2.05	2.30	2.52	2.57	2.53
DPS (US\$)	1.65	0.61	0.70	0.81	0.93	1.07	1.23	1.41
Net (debt) / cash	(3,578)	(4,076)	(4,442)	(4,870)	(5,292)	(5,632)	(5,956)	(6,286)
Profitability/valuation	12/13	12/14	12/15	12/16E	12/17E	12/18E	12/19E	12/20E
EBIT margin %	58.5	59.1	53.7	57.0	57.9	58.5	57.9	56.7
ROIC (EBIT) %	11.3	11.4	9.4	10.8	11.0	11.1	10.7	10.1
EV/EBITDA (core) x	12.0	12.7	13.9	13.0	11.5	10.4	9.9	9.7
P/E (UBS, diluted) x	18.4	18.8	17.2	21.3	19.0	17.3	17.0	17.3
Equity FCF (UBS) yield %	(8.8)	(5.3)	(4.4)	(6.0)	(5.6)	(4.0)	(3.6)	(3.3)
Net dividend yield %	5.5	1.7	2.0	1.8	2.1	2.4	2.8	3.2

Source: Company accounts, Thomson Reuters, UBS estimates. Metrics marked as (UBS) have had analyst adjustments applied. Valuations: based on an average share price that year, (E): based on a share price of US\$43.72 on 19 Apr 2016 19:37 EDT

\* Exception to core rating bands; See page 281.

### **Dynegy, Inc. Investment case**

Dynegy shares are likely to be driven by moves in gas and power prices as well as by announcements with respect to financial restructuring/M&A considerations, as peer coal and gas generators weigh selling their coal portfolios. Equity valuation is driven in part by option value to either a power recovery and credit markets. We think the shares will outperform as the strategy is executed by the new management at the helm, led by Bob Flexon, who previously served as NRG Energy's CFO/COO.

### **NRG Energy Inc. Investment case**

Shares remain particularly levered to natural gas prices through its large coal portfolio in Texas; that said, we look for market reforms in ERCOT to improve heat rates independent of natural gas prices. NRG is exposed to Texas market reforms, which is our top theme in the sector. We think the name may be appealing to those seeking substantial leverage to gas and power prices.

### **Talen Energy Corp Investment case**

Talen is a coal and nuclear-oriented independent power producer (IPP) operating primarily in PJM created from the spin of PPL Energy Supply and Riverstone. The new IPP primarily has assets in PJM and ERCOT with a willingness to expand into other competitive power markets. The strategy is to grow cash flows in the capacity and energy markets both organically and via M&A. The investment case is premised on Talen earning additional capacity payments in PJM, extracting further synergies from its PPL/Riverstone deal, and being able to grow via debt-heavy power asset acquisitions. We see the standalone fundamental outlook as facing challenges with PJM East (in PSEG and PPL zones) consistently trading at a discount now to PJM West prices – and see further new plant entry only exacerbating these concerns. We believe potential for LBO is real following media headlines.

### **ITC Holdings Corp Investment case**

ITC is a pure-play transmission investment company operating primarily in the United States. ITC focuses on FERC regulated transmission opportunities and benefits from its status as an independent company via incentive payments. Risks to the story include FERC Order 1000 competition, declining FERC ROEs, and a slowdown in transmission development. Converting the company to a REIT could offer upside but management has not committed to that path.

### **Calpine Corporation Investment case**

Calpine has numerous opportunities related to its exposure to the Texas power markets, California carbon via its geothermal assets, and increased coal-to-gas switching in the eastern United States. Although depressed today, we still view Texas as among the US power market with the most upside due to increasing environmental air quality regulations. In the Southeast, we believe monetization of its fleet via long-term contracts or outright sales to regulated utilities will drive further upside, as the LS Power deal indicates. Driven by cash from contracted assets, especially the Geysers geothermal, we see strong free cash flow generation which should facilitate reduction of debt in the future.

## Valuation Method and Risk Statement

Risks for Utilities and Independent Power Producers (IPPs) primarily relate to volatile commodity prices for power, natural gas, and coal. Risks to IPPs also stem from load variability, and operational risk in running these facilities. Rising coal and, to a certain extent, uranium prices could pressure margins as the fuel hedges roll off Competitive Integrations. Further, IPPs face declining revenues as in the money power and gas hedges roll off. Other non-regulated risks include weather and for some, foreign currency risk, which again must be diligently accounted in the company's risk management operations. Major external factors, which affect our valuation, are environmental risks. Environmental capex could escalate if stricter emission standards are implemented. We believe a nuclear accident or a change in the Nuclear Regulatory Commission/Environment Protection Agency regulations could have a negative impact on our estimates.

Risks for regulated utilities include the uncertainty around the composition of state regulatory Commissions, adverse regulatory changes, unfavorable weather conditions, variance from normal population growth, and changes in customer mix. Changes in macroeconomic factors will affect customer additions/subtractions and usage patterns.

## Required Disclosures

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### UBS Investment Research: Global Equity Rating Definitions

12-Month Rating	Definition	Coverage <sup>1</sup>	IB Services <sup>2</sup>
<b>Buy</b>	FSR is > 6% above the MRA.	49%	32%
<b>Neutral</b>	FSR is between -6% and 6% of the MRA.	38%	26%
<b>Sell</b>	FSR is > 6% below the MRA.	14%	19%
Short-Term Rating	Definition	Coverage <sup>3</sup>	IB Services <sup>4</sup>
<b>Buy</b>	Stock price expected to rise within three months from the time the rating was assigned because of a specific catalyst or event.	<1%	<1%
<b>Sell</b>	Stock price expected to fall within three months from the time the rating was assigned because of a specific catalyst or event.	<1%	<1%

Source: UBS. Rating allocations are as of 31 March 2016.

1: Percentage of companies under coverage globally within the 12-month rating category.

2: Percentage of companies within the 12-month rating category for which investment banking (IB) services were provided within the past 12 months.

3: Percentage of companies under coverage globally within the Short-Term rating category.

4: Percentage of companies within the Short-Term rating category for which investment banking (IB) services were provided within the past 12 months.

**KEY DEFINITIONS:** **Forecast Stock Return (FSR)** is defined as expected percentage price appreciation plus gross dividend yield over the next 12 months. **Market Return Assumption (MRA)** is defined as the one-year local market interest rate plus 5% (a proxy for, and not a forecast of, the equity risk premium). **Under Review (UR)** Stocks may be flagged as UR by the analyst, indicating that the stock's price target and/or rating are subject to possible change in the near term, usually in response to an event that may affect the investment case or valuation. **Short-Term Ratings** reflect the expected near-term (up to three months) performance of the stock and do not reflect any change in the fundamental view or investment case. **Equity Price Targets** have an investment horizon of 12 months.

**EXCEPTIONS AND SPECIAL CASES:** **UK and European Investment Fund ratings and definitions are:** **Buy:** Positive on factors such as structure, management, performance record, discount; **Neutral:** Neutral on factors such as structure, management, performance record, discount; **Sell:** Negative on factors such as structure, management, performance record, discount. **Core Banding Exceptions (CBE):** Exceptions to the standard +/-6% bands may be granted by the Investment Review Committee (IRC). Factors considered by the IRC include the stock's volatility and the credit spread of the respective company's debt. As a result, stocks deemed to be very high or low risk may be subject to higher or lower bands as they relate to the rating. When such exceptions apply, they will be identified in the Company Disclosures table in the relevant research piece.

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**UBS Securities LLC:** Julien Dumoulin-Smith; Michael Weinstein; Paul Zimbardo; Jeremiah Booream.

## Company Disclosures

Company Name	Reuters	12-month rating	Short-term rating	Price	Price date
<b>AES Corporation</b> <sup>16</sup>	AES.N	Neutral	N/A	US\$11.50	19 Apr 2016
<b>Ameren Corp.</b> <sup>16</sup>	AEE.N	Neutral	N/A	US\$49.12	19 Apr 2016
<b>American Electric Power, Inc.</b> <sup>4, 6a, 7, 16</sup>	AEP.N	Buy	N/A	US\$65.84	19 Apr 2016
<b>Avista Corp</b> <sup>4, 6c, 7, 16</sup>	AVA.N	Sell	N/A	US\$40.72	19 Apr 2016
<b>Calpine Corporation</b> <sup>4, 6a, 7, 16</sup>	CPN.N	Buy	N/A	US\$15.73	19 Apr 2016
<b>CMS Energy Corporation</b> <sup>16</sup>	CMS.N	Neutral	N/A	US\$41.79	19 Apr 2016
<b>Consolidated Edison</b> <sup>2, 4, 5, 6a, 16</sup>	ED.N	Sell	N/A	US\$76.01	19 Apr 2016
<b>Dominion Resources</b> <sup>2, 4, 5, 6a, 6b, 6c, 7, 16</sup>	D.N	Neutral	N/A	US\$72.82	19 Apr 2016
<b>DTE Energy Co.</b> <sup>2, 4, 6a, 7, 16</sup>	DTE.N	Buy	N/A	US\$89.55	19 Apr 2016
<b>Duke Energy</b> <sup>2, 4, 5, 6a, 6c, 7, 16</sup>	DUK.N	Buy	N/A	US\$79.79	19 Apr 2016
<b>Dynegy, Inc.</b> <sup>16</sup>	DYN.N	Buy	N/A	US\$17.05	19 Apr 2016
<b>Edison International</b> <sup>4, 6a, 7, 16</sup>	EIX.N	Buy	N/A	US\$71.42	19 Apr 2016
<b>Empire District Electric Company</b> <sup>16, 19</sup>	EDE.N	Neutral (CBE)	N/A	US\$33.45	19 Apr 2016
<b>Entergy Corp.</b> <sup>16</sup>	ETR.N	Sell	N/A	US\$76.43	19 Apr 2016
<b>Eversource Energy</b> <sup>16</sup>	ES.N	Neutral	N/A	US\$57.04	19 Apr 2016
<b>Exelon Corp.</b> <sup>6a, 7, 16</sup>	EXC.N	Neutral	N/A	US\$34.80	19 Apr 2016
<b>FirstEnergy Corp.</b> <sup>7, 16</sup>	FE.N	Neutral	N/A	US\$35.50	19 Apr 2016
<b>ITC Holdings Corp</b> <sup>16, 19</sup>	ITC.N	Neutral (CBE)	N/A	US\$43.72	19 Apr 2016
<b>NextEra Energy</b> <sup>4, 6a, 6c, 7, 16</sup>	NEE.N	Buy (UR)	N/A	US\$118.10	19 Apr 2016
<b>NextEra Energy Partners LP</b> <sup>2, 4, 6a, 16</sup>	NEP.N	Neutral	N/A	US\$26.75	19 Apr 2016
<b>NRG Energy Inc.</b> <sup>7, 16</sup>	NRG.N	Buy	N/A	US\$14.31	19 Apr 2016
<b>NRG Yield</b> <sup>16</sup>	NYLDA.N	Buy	N/A	US\$14.46	19 Apr 2016
<b>PG&amp;E Corporation</b> <sup>16</sup>	PCG.N	Neutral	N/A	US\$59.58	19 Apr 2016
<b>Pinnacle West Capital Co.</b> <sup>6a, 16</sup>	PNW.N	Neutral	N/A	US\$74.85	19 Apr 2016
<b>Portland General Electric Company</b> <sup>16</sup>	POR.N	Buy	N/A	US\$39.64	19 Apr 2016
<b>PPL Corporation</b> <sup>2, 4, 5, 6a, 6c, 7, 16</sup>	PPL.N	Buy	N/A	US\$37.80	19 Apr 2016
<b>Public Service Enterprise Group</b> <sup>16</sup>	PEG.N	Buy	N/A	US\$47.12	19 Apr 2016
<b>SCANA Corp.</b> <sup>2, 4, 6a, 7, 16</sup>	SCG.N	Neutral	N/A	US\$69.88	19 Apr 2016
<b>Sempra Energy</b> <sup>2, 4, 6a, 6c, 7, 16, 18</sup>	SRE.N	Buy	N/A	US\$104.21	19 Apr 2016
<b>Southern Company</b> <sup>2, 4, 5, 6a, 6c, 7, 16</sup>	SO.N	Sell	N/A	US\$51.00	19 Apr 2016
<b>Talen Energy Corp</b> <sup>4, 6a, 16</sup>	TLN.N	Neutral	N/A	US\$12.30	19 Apr 2016
<b>TECO Energy Inc.</b> <sup>13, 16</sup>	TE.N	Neutral	N/A	US\$27.78	19 Apr 2016
<b>WEC Energy Group Inc.</b> <sup>16</sup>	WEC.N	Sell	N/A	US\$59.14	19 Apr 2016
<b>Westar Energy, Inc.</b> <sup>6a, 16</sup>	WR.N	Neutral	N/A	US\$51.21	19 Apr 2016
<b>Xcel Energy Inc.</b> <sup>7, 16</sup>	XEL.N	Sell	N/A	US\$41.16	19 Apr 2016

Source: UBS. All prices as of local market close.

Ratings in this table are the most current published ratings prior to this report. They may be more recent than the stock pricing date

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