US Power
2Q16 Power Preview: Sparking Up

Equities
Americas
Electric Utilities

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Breathing room into constructive 2Q earnings season for power sector
We see modest upside into 2Q for IPPs. Recent power and gas improvement provides further latitude for equities to improve; we emphasize both CPN and DYN as having the most upside. We expect commentary on 2Q calls to prove generally supportive with a focus on refinancing and cost reductions. By contrast, we don't expect companies to meaningfully reveal their new EBITDA & FCF trajectories in 2019 and 2020 given the latest capacity auction results; this would appear a headwind to address at a later point. Moreover, we see a potential break in coal pricing trends as we see an inflection; by contrast, we perceive sentiment as nearing its contemplated 'targets' for power and gas prices, leaving a more limited upside skew. We include further key debates below.

Quarterly Power Prospects Look Reasonable; New England and MISO on deck
We expect results across at least NRG and CPN to prove constructive vs. Street expectations. Moreover, we don't expect any negative guidance revisions for covered companies; in fact, our initial look at 2017 EBITDA guidance (with 3Q results) for Calpine suggests it is at least inline with Street expectations, if not modestly ahead. In the near-term, we prefer exposure to New England given prospects for gas pipeline delays. Further, we see upside into forthcoming MISO reforms. Both would appear particularly well suited to DYN's core businesses. We continue to prefer ERCOT through the medium term given retirement prospects and depressed sparks limiting much new build of any technology type.

Key power datapoint will be EXC's Analyst Day on August 10
While regulated utility guidance is likely to be inline as mgmt simply rolls forward its 7-9% EPS growth guidance out to 2019 or 2020 – key will be datapoints around ExGen prospects, particularly carbon credits both in New York and elsewhere (PA?). At a minimum, we see shares as poised to move up into NY ZEC approval on ~Aug 1st.

2H focus will clearly be on the Carbon & Climate change focus of Election
We suspect 2H16 will clearly migrate towards a binary view of the US election cycle with equities trading around expectations for eventual implementation of Clean Power Plan (CPP) or any future incarnation once through the judicial and any further executive branch review. We emphasize both candidates detail views substantially different than policies undertaken in the latest Obama administration.

Focus remains on EFH – and what signals it provides to ERCOT market?
Among the critical focuses in power remains what will come of EFH post-bankruptcy – and in particular – with its wide array of legacy coal plants; retirements had been anticipated as a meaningful contributor to market improvement here. We are incrementally more cautious of late after indications it would keep assets open through continued cost reductions. A further emerging theme in 2Q will be consolidation once more, against a backdrop where generators are not limited due to market power?

Regional Haze is stayed by the 5th Circuit Court: Negative Outcome for ERCOT
This is a modest headwind to our ERCOT thesis. The latest decision is not necessarily a surprise following similar moves by the court in implementing the regs in adjacent states; EPA has been successful in subsequently implementing the rules largely intact despite appeal in many recent cases (notably high profile decisions upholding Haze was in adjacent states of OK and NM). At a minimum, the effect of the stay is to delay rule implementation by upwards of a year, beyond potential for rule moderation (could rules be reduced to have less of a disproportionate impact on legacy EFH coal generation assets such as Big Brown?). The wider question is whether EFH would opt to retire units once it gets final clarity on Regional haze implementation (with forecasted FCF deficits through this period) or only upon rule start dates in early 2020s?

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Latest Thoughts on Power Markets

We present below key themes on the power sector heading into 2Q results.

(1) **Retail debate is back:** We note valuation of retail businesses has once more garnered headlines as the question is *how* to value these businesses for NRG, EXC, and now EFH's competitive segment once more. Companies continue to argue the merits of garnering an equivalent EV/EBITDA multiple on these businesses as their generation as they seem as effectively an extension of their physical generation operations. We continue to take a divergent view here.

a. **Not all retail created the same.** We caution investors that the residential retail strategies in Texas pursued by NRG and EFH (TXU Energy) rely on high margins on a relatively smaller set of residential customers. In contrast, EXC's business relies on high volumes at substantially lower margins. We note each of these has their own respective risks, albeit drive the bulk of the consolidated FCF at each one of these Genco entities.

b. **Lower generation multiples actually drive compression in valuation spread.** Ascribing 6-7x EV/EBITDA across most generation valuations of late, we note the 5-6x we apply to the retail businesses arguably has eliminated any historic discount already.

c. **Keeping assets around to reduce the risk.** We also note in EFH's recent presentation that they appear to emphasize an integrated approach. We caution investors that even assets in Texas with negative FCF appear to be kept open in an effort to hedge their otherwise lucrative retail operations. *The question is just how much of a loss will be tolerated from a generation asset in order to hedge retail risk?*

(2) **Harvesting cash from legacy assets:** A key theme emerging is reducing the run-rate of maintenance capex in assets to improve FCF of generation businesses. We suspect companies from NRG, to DYN, to FE to focus on improving FCF through reduced capex. We tie future retirements of largely FCF negligible assets to discrete capex decisions.

a. **What is the next 'big' capex item?** It's actually a modest investment in a combination of **Coal Ash (CCRs)** and **Effluent Limitation Guidelines (ELGs)** dictating waste water rules on plants. These two have a delayed impact with requirements kicking in 2018+, but should add $10's of Mns to plant spend (a potentially unpalatable figure in the current environment).

b. **Coal is a focus as managing down inventories.** A tangent remains coal pricing and rail rates as companies attempt to bring down their own cost structures. It would appear a modest piece of the overall pressure

(3) **PJM auction redux: explaining the results and what they mean.** We expect companies to address the implications of the latest PJM capacity auction results from Late May. We note companies such as NRG appear to be poised to talk down future expectations after the auction, particularly around upside prospects for their GenOn portfolio.

a. **Reducing costs.** We look for FE to reduce its Competitive Business costs yet again as a function of the lower capacity revenues. We note the lower level of investment in assets stands in *contrast* to the higher levels of reliability required under new Capacity Performance (CP) standards.

(4) **Foreign investment remains a focal point.** We emphasize low interest rates remain a key driver of infrastructure investment across the risk spectrum including in IPP assets. With the downtick in rates of late, we continue to expect new build to stretch into subsequent auctions. We note risk taking for equity returns continues to see a downside bias into the single digits for downside equity cases for new merchant gas projects.

a. **Expect continued wave of refinancings.** Companies will continue to refi their debt balances, capitalizing on lower interest rates and credit spreads.

(5) **Gas Pipeline delays bode well**. We note recent delays in multiple pipeline projects as well as clear risks to other ongoing efforts remain a source of upside to power, particularly across the Northeast. Delayed electric transmission assets play a similar role in supporting congestion prices.

(6) **La Nina & Weather Trade:** Can Summer Heat drive more of a bid in Power? We suspect so, at least via a reduction in coal inventories and pricing. We note a re-emergence in the summer 'weather' trade. In fact, we see many energy investors as narrowly focused on 2017 improvement. In turn, we see this playing out in gas forwards, where 2017 is a 'peak' year at $3.17/MMBtu of late, backwardated in subsequent years.

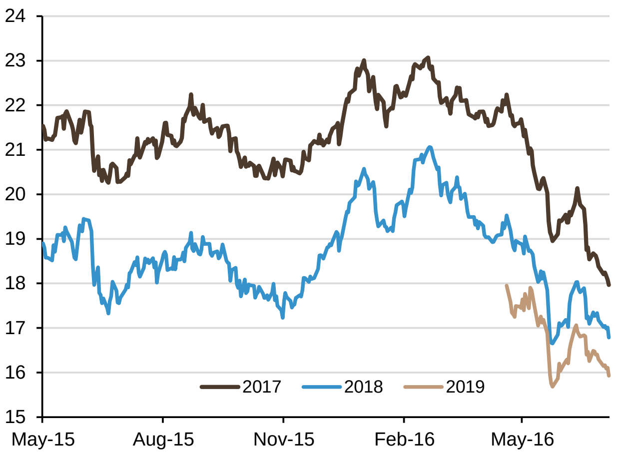
PJM: Investor Denial on Limited Recovery

Following the auction results in May, investors continue to see upside to a PJM recovery next year. While admittedly it should be $20-30/MW-day under our latest scenarios, we don't see the +$70/MW-day contemplated by the initial PJM sensitivities disclosed for a prior auction under a 100% Capacity Performance (CP) implementation. We expect companies to gradually moderate expectations through the 2Q reporting season; we also note backwardated PJM sparks are also likely to grab growing attention to this issue.

Capacity is Leading Indicator: New Gen Pushes Down Spark Spreads

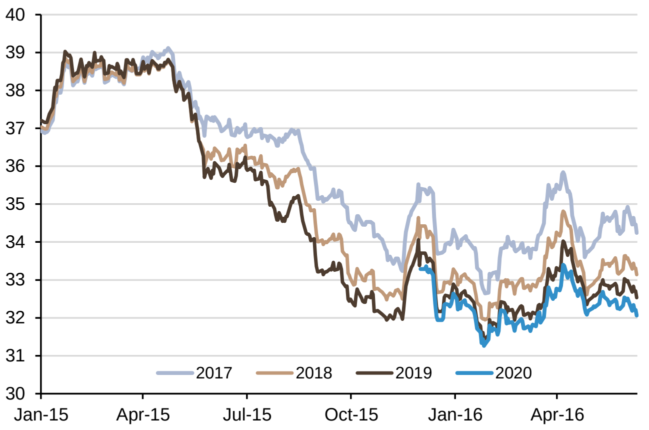
Forward looking expectations continue to decline in PJM amidst concerns over new build in the market. We have been concerned for some time that builds would eventually translate not just into capacity price pressures but into wider Spark spread pressures they begin to reach in-service this year and next in meaningful quantities. We are not surprised to continue to see a meaningful YoY backwardation of forward sparks.

Figure 1: PJM Spark Spreads @ 7.2 HR ($/MWh)



Source: Platts and UBS estimates

Figure 2: PJM ATC Power Prices ($/MWh)

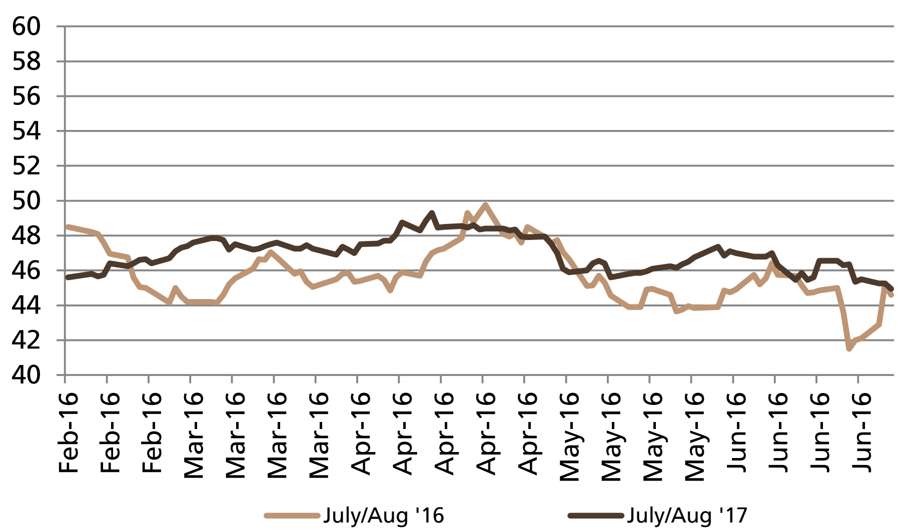


Source: Platts and UBS estimates

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. We note companies appear to be increasingly comfortable with exposure to CP risk despite no risk hours having been incurred yet; the CP program only *began* in May, 2016. We note many continue to work diligently on their compliance strategies which include principally fuel assurance (LDC workarounds and dual-fuel).

Figure 3: Recent PJM Summer Forward Trends: Coming Back a Bit ($/MWh)



Source: Platts

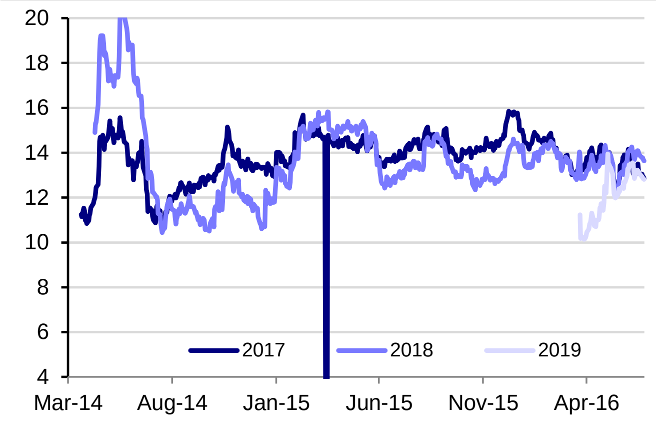
How do NI Hub (Chicago) price trends look? Better.

Although the trend has been overwhelmingly negative we have seen ATC prices stabilize and even recover off their lows. 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. We emphasize recent closure announcement of Quad Cities is just the first of potentially multiple nuclear plant retirements in the state. We suspect EXC will be diligent in retiring additional assets as the state does not act on their efforts to receive relief for their zero carbon efforts.

Nuclear retirement drive improving prospects

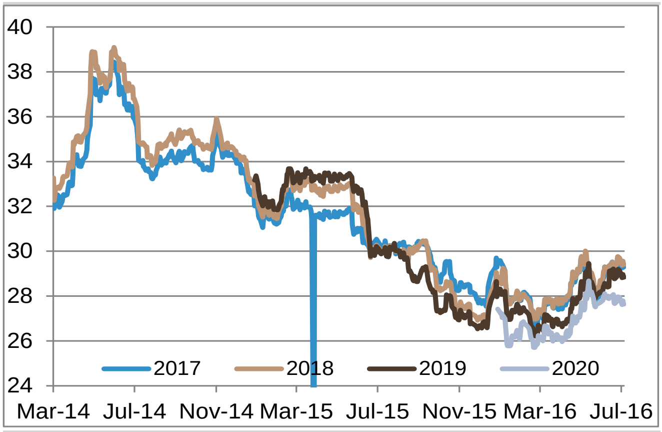
So does rising PRB prices in a marginal coal market.

Figure 4: NI Hub Spark Spreads @ 7.2 HR ($/MWh)



Source: Platts and UBS estimates

Figure 5: NI Hub ATC Power Prices ($/MWh)



Source: Platts and UBS estimates

Who's exposed to PJM? Providing the Sensitivities:

Figure 6: Sensitivity - $1/kW Change in Capacity Pricing - PJM

PJM Capacity Market Upside	TLN	DYN	NRG	EXC	FE	PEG	AEP	CPN	AES	NEE	D	Total
Nameplate Capacity (MW)	11,969	11,940	18,658	22,142	9,477	12,042	8,668	4,946	3,198	1,029	1,408	81,568
EFORd Adj. (MW)	11,271	11,265	17,506	20,794	8,942	11,333	8,135	4,663	2,866	964	1,228	76,430
Clearing Price in 2016/17 $/MW-Day	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	
Clearing Price in 2017/18 $/MW-Day	$152	$152	$152	$152	$152	$152	$152	$152	$152	$152	$152	
$10/MW-day Sensitivity ($M)	**41**	**41**	**64**	**76**	**33**	**41**	**30**	**17**	**10**	**4**	**4**	**279**
Impact to EPS	**$ 0.21**	**N/A**	**N/A**	**$ 0.06**	**$ 0.05**	**$ 0.05**	**$ 0.04**	**N/A**	**$ 0.01**	**$ 0.01**	**$ 0.00**	
2017 EPS or EBITDA	**$705**	**$1,043**	**$2,976**	**$ 2.67**	**$ 2.36**	**$ 2.93**	**$ 3.88**	**$2,186**	**$ 1.25**	**$ 6.74**	**$ 3.81**	
% of total 2017 UBS Estimate	**5.8%**	**3.9%**	**2.1%**	**2.1%**	**2.1%**	**1.8%**	**1.0%**	**0.8%**	**0.8%**	**0.1%**	**0.1%**	

Source: Company Filings, PJM, SNL, and UBSe

For further background we include links to recent reports below:

6/29/16: RAAB Roundtable on PJM Market
6/9/16: Flaring Some Gas in PJM
5/27/16: Where is it Going & Why The Street is Too ...
5/27/16: PJM Auction: The Reviews Are In [Includes ...
5/26/16: PJM Results Take Two: Who Cleared?
5/25/16: PJM Results: Generation Gap
5/23/16: Awaiting the Score for the Annual PJM Auction
5/20/16: PJM Parameter Update is Slightly Positive
5/17/16: PJM Capacity Auction Survey: Exhibiting ...

ERCOT: Don't Everyone Move At Once

Waiting for the retirement cycle to start

We emphasize the key story in ERCOT for any real improvement remains an asset rationalization cycle of older, less nimble assets – be it coal or gas. The positive unlevered cash flow, coupled with constructive commentary on asset level profitability alongside prospects for further cuts to fuel, SG&A, and O&M provides less comfort on the margin to the ERCOT recovery. While we still appreciate the ERCOT overall, the ability for the sector to continue to innovate and reduce costs remains an impediment to its own recovery. We emphasize DYN may prove the first to cut its coal plant, but the timeline for others to follow is less clear. We emphasize the Twin Oaks coal plant owned by Blackstone is a lignite coal plant and appears roughly breakeven. Further, the question retirements for EFH appears tied to single capex events as slight or modest FCF losses at each of the more challenged units appears to be palatable amidst ongoing efforts to cut costs and offset retail risk.

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

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.

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 Coleto Creek coal plant given its smaller size (635MW) and potential exposure to future environmental regulations. Facing loses 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.

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.

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 IPP top pick

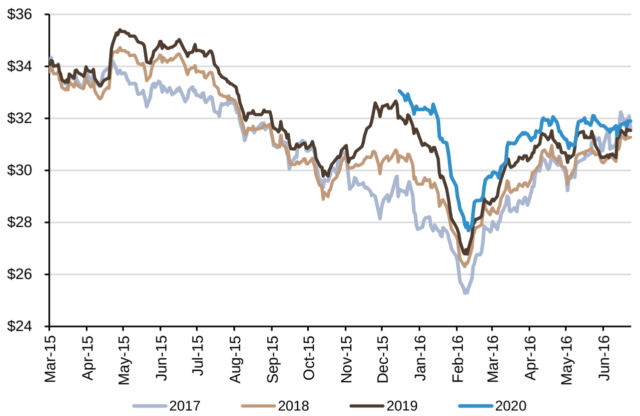
What is increasingly clear is most IPPs are actually losing cash/close to break-even in operating their physical assets (ex-Retail), including NRG, EFH (using their previous disclosures), TLN (gas portfolio), and DYN (Engie). Rather, power hedges and retail enable positive overall cash flows for NRG 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.

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. We emphasize NRG's STP Plant is likely a ~breakeven FCF asset, albeit the latest recovery likely puts this back into the green. Comanche Peak at $26/MWh is clearly well in the money.

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

Figure 7: ERCOT-Houston ATC Power Prices($/MWh) – meaningfully recovering



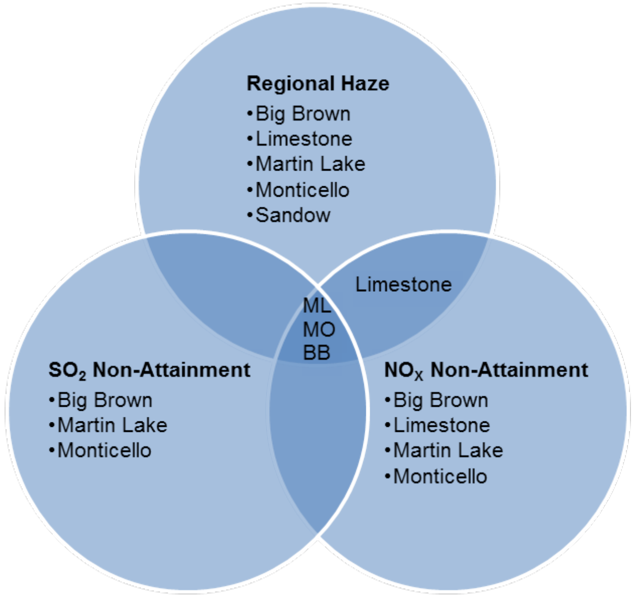
Source: Platts

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_x emissions, in this particular instance the regulations are focused on reducing SO_2 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 8: Texas Environmental Regulations



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

Renewables threaten the recovery

But when will the renewables hit (again)?

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

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 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.

This price is entry is declining

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.

Once CREZ is full don't look for another set of projects yet

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 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.

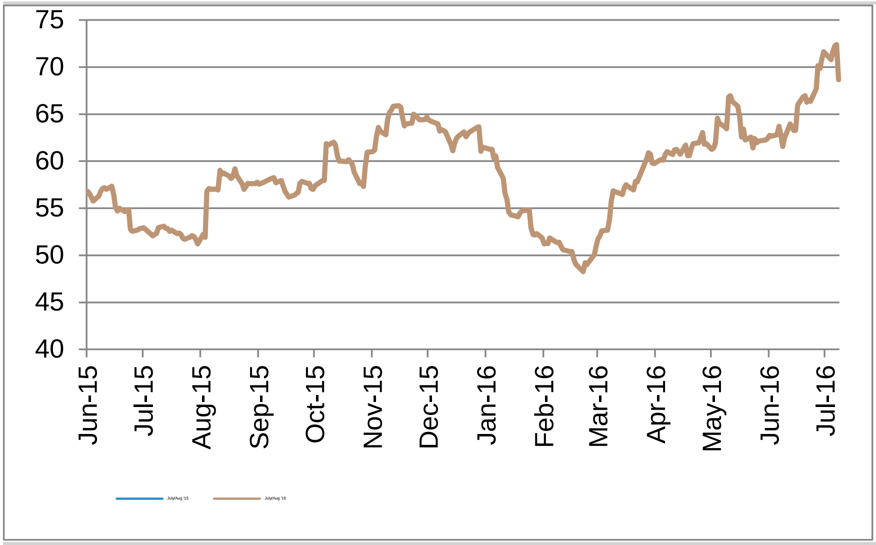
Summer-Time Concerns: Getting a bit Windy of Late?

Challenging the assertion that wind doesn't blow during the summer in Texas

Among the other growing themes in the market is the penetration of wind. We note recent above-average wind dispatch further calls into question expectations for the total potential wind dispatch into the market at seasonally peak periods, likely weighing on Summer peak price expectations (July/Aug).We emphasize last week wind in Texas claimed a new high water mark for mid-summer dispatch at ~23% of total market share during the hotter ERCOT day – this translates to a roughly ~low 70% capacity factor on the existing wind fleet during a heat wave (despite coincident historic peak expectations for wind during on-peak periods in the ~20% range).

Of late, the summer forwards have recovered to a multi-year high as the split between peak and off-peak has reached new disparities. The question is whether expectations for above-average weather and limited impact from renewables (wind) during peak times will enable this price formation. Overall, recent price trends of late remain quite supportive.

Figure 9: Summer July/Aug 2017 Curve for ERCOT Houston



Source: Platts

PUCT Looking at Retail Again

Reforms which increase the rate of customer switching could negatively impact players with large market share such as NRG

On June 9th the Public Utilities Commission of Texas (PUCT) announced that it will be reviewing the practices of competitive electric retail providers in the state. A special meeting on June 21st will be held with stakeholders and hosted by Chairman Donna Nelson to help make the shopping process easier for consumers but addressing what have been perceived as confusing offers. In Texas most

customers can shop for their retail electric provider on www.powertochoose.org. Some of the incumbent retail providers have proposed closing the PUCT-managed website in favor of individually selling plans to consumers but the PUCT would prefer to maintain the independent site. Commissioner Ken Anderson commented that retail providers could face sanctions and enforcement actions for failure to comply with the rules.

On June 11th there were 312 offers on PowertoChoose which ranged from 1¢/kWh to 13.5¢/kWh with companies including GexaEnergy, InfiniteEnergy, and Reliant (NRG Energy) offering 3¢/kWh or lower advertised rates. The rates are based on 1,000kWh monthly usage and have significantly higher costs per kWh at different volumes due to bill credits at 1,000kWh per month. For example, in Reliant's "Bulls-Eye 3" plan there is a credit for usage between 1,000-2000kWh per month which we detail below (Further details are available here). Per the EIA the average monthly consumption in Texas was 1,158kWh at an average price of 11.86¢/kWh in 2014. Although the average consumption is above the 1,000kWh level, this is likely skewed by the peak summer months.

Bill credits for narrow usage windows, high termination fees, and other bill terms make it challenging for customers to accurately shop for electricity.

Figure 10: Relliant Bull's-Eye 3 Plan Scenario Analysis

Relliant Bull's-Eye 3 Plan Scenario Analysis					
Usage (kWh)	500	Usage	1,000	Usage	2,000
Base Charge ($)	$0.00	Base Charge	$0.00	Base Charge	$0.00
Energy Charge ($/kWh)	$0.034	Energy Charge	$0.034	Energy Charge	$0.034
Credit ($)	-$40.00	Credit	-$40.00	Credit	-$40.00
Delivery Charge ($/kWh)	$5.25	Delivery Charge	$5.25	Delivery Charge	$5.25
Energy Delivery ($/kWh)	$0.0307	Energy Delivery	$0.0307	Energy Delivery	$0.0307
Monthly Fixed ($)	$5.25	Monthly Fixed	$5.25	Monthly Fixed	$5.25
Monthly Variable ($)	$32.34	Monthly Variable	$64.67	Monthly Variable	$129.35
Monthly Credit ($)	$0.00	Monthly Credit	-$40.00	Monthly Credit	$0.00
Total Cost ($)	$37.59	Total Cost	$29.92	Total Cost	$134.60
All-In Cost per kWh	**$0.075**	**All-In Cost per kWh**	**$0.030**	**All-In Cost per kWh**	**$0.067**

Source: PowertoChoose

Why does this matter? NRG Energy and Energy Future Holdings (EFH) are both leaders in the Texas retail market and any reforms which encourage customer switching could reduce cash flows going forward. Retail operations represent 30% of NRG's EBITDA ex-NYLD and a disproportionate amount of their free cash flows.

Debate is refocusing on the retail – is this keeping generation open? We emphasize given the robust margins earned by this business for incumbents, the question is whether this is acting as a barrier to closing plants that are otherwise garnering negative EBITDA and FCF. With multiple companies emphasizing the integrated nature of the platform (and hence integrated nature of the profitability seemingly), we would suspect that this is the primary culprit behind the paucity of generation retirements thus far in Texas.

Further details are available at Ofgem's switching program site here.

Additionally, the latest on Ofgem and the CMA's competition assessment are here.

ERCOT: 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 Confuzed] **[Regional Haze regulations]**

Figure 11: May CDR Report -> Looking at High Reserve Margins

CDR Update w/ UBS Adjustments	2017	2018	2019	2020	2021
Load Forecast:					
Total Summer Peak Demand (based on normal w eather)	71,416	72,277	73,663	74,288	74,966
less: LRs Serving as Responsive Reserve	1,153	1,153	1,153	1,153	1,153
less: LRs Serving as Non-Spinning Reserve	0	0	0	0	0
less: Emergency Response Service (10- and 30-min ramp products)	1507	1507	1,507	1,507	1,507
less: TDSP Standard Offer Load Management Programs	208	208	208	208	208
Firm Load Forecast, MW	**68,548**	**69,409**	**70,795**	**71,420**	**72,098**
Prior Load Forecast	*68,341*	*69,276*	*70,329*	*71,254*	*72,180*
Change vs., Prior	*0.3%*	*0.2%*	*0.7%*	*0.2%*	*-0.1%*
Nominal Growth in Load YoY (MW)	485	861	1,386	625	678
Y/Y %	0.7%	1.3%	2.0%	0.9%	0.9%
5-year CAGR					1.2%
Operational Generation, MW					
Installed Capacity, Thermal/Hydro	65,990	66,165	65,325	65,325	65,325
Capacity from Private Use Netw orks	4,292	4,540	4,536	4,465	4,436
Non-Coastal Wind, Peak Average Capacity Contribution (12%)	1,693	1,693	1,693	1,693	1,693
Coastal Wind, Peak Average Capacity Contribution (55%)	1,015	1,015	1,015	1,015	1,015
RMR Capacity to be under Contract	0	0	0	0	0
Capacity Contribution - Non-Synchronous Ties, MW	577	577	577	577	577
Sw itchable Capacity, MW	2,972	2,972	2,972	2,972	2,972
Available Mothballed Capacity, MW	805	805	805	805	805
Solar Utility-Scale, Peak Average Capacity Contribution (80%)	230	230	230	230	230
Planned Resources (not w ind) w ith Signed IA, Air Permits and Water Rights, MW	1,400	6,207	7,185	7,425	7,425
Planned Non-Coastal Wind w ith Signed IA, Peak Average Capacity Contribution (12%)	838	1,083	1,167	1,167	1,167
Planned Coastal Wind w ith Signed IA, Peak Average Capacity Contribution (55%)	305	619	619	619	619
Planned Solar Utility-Scale, Peak Average Capacity Contribution (80%)	1,177	1,412	1,412	1,412	1,412
Total Resources, MW	**81,295**	**87,319**	**87,538**	**87,707**	**87,678**
less: Sw itchable Capacity Unavailable to ERCOT, MW	-300	-300	-300	-300	0
less Retiring Units, MW	0	0	0	0	0
Resources, MW	**80,995**	**87,019**	**87,238**	**87,407**	**87,678**
Ex-new units (Cumulative)	*2,320*	*3,115*	*3,199*	*3,199*	*3,199*
Total Resources, ex-new units	78,675	83,905	84,039	84,208	84,479
Reserve Margin (Official May 2016 CDR)	**18.2%**	**25.4%**	**23.2%**	**22.4%**	**21.6%**
Previous forecast (May 2015 CDR update)	*18.5%*	*21.4%*	*18.7%*	*17.1%*	*16.1%*

Source: ERCOT and UBS estimates

MISO: Riding the Roller Coaster

Looking at the latest on Capacity Reform

With the long-debated process reaching some conclusion, we note a continued open division between the Market Monitor and MISO on the 'right' approach for its new capacity construct. We note competing constructs are focused on:

(7) Whether to pursue a forward (3-yr) vs. prompt year procurement?

(8) Who is eligible to participate (all supply or just competitive?)

(9) What demand would be served? Just competitive zones or all legacy?

(10) What kind of demand curve? Sloped , extended slope or otherwise

We note an ongoing focus on mitigating *<u>price volatility</u>* *for merchant generators as well as demand.*

<u>What's the timeline from here?</u>

- July 14: Brattle Presentation
- July 20: Tariff Language and Business rules Posted
- August 3/4: RASC Meeting
- August 8: Markets Committee of the Board

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

Although the latest capacity auction surpassed our estimates (to the upside), the ~50% decline versus the prior year will still significantly pressure merchant generators in the Illinois region.

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

Figure 12: MISO Capacity Auction Snapshot

MISO Local Resource Zone	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10
Region	MN, ND, Western WI	Eastern WI, Upper MI	IA	IL	MO	IN, KY	MI	AR	LA, TX	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 l ACP = Auction Clearing Price; ZRC = Zonal Resource Credits; FRAP = Fixed Resource Adequacy Plan; CONE = Cost of New Entry

What will Dynegy do? We note the move to retire individual units at both Newton and Baldwin was unusual in our view, where coal generators have historically opted to keep more economic units intact, shutting smaller less profitable units altogether. *We would not doubt further retirements if the ongoing reforms prove insufficient.*

Distilling Last Year's Supply Curve for Clues on Clinton Retirement

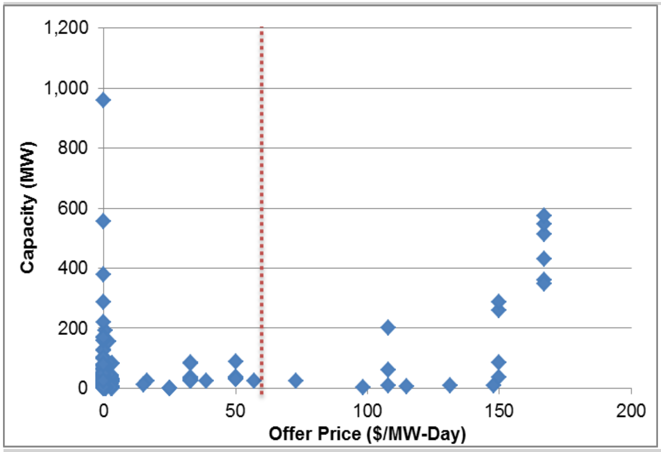
What can the 2015-2016 MISO auction teach us about the current 2016-2017 auction?

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).

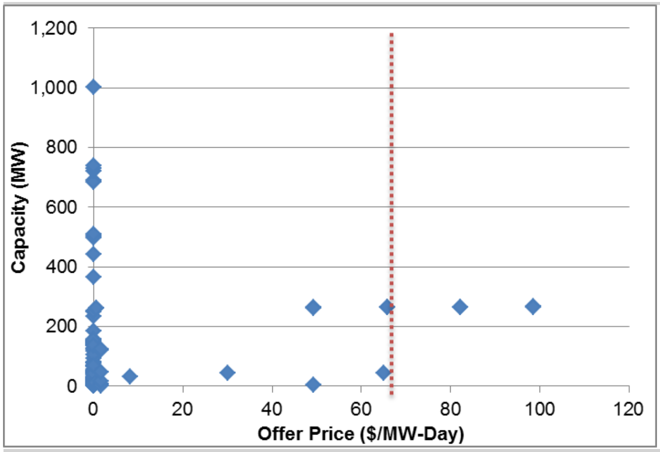
Exelon commented last auction that it has historically bid in its 1,069MW Clinton nuclear plant as a price taker and in the 2015-2016 auction it did execute bilateral contracts reducing the about of capacity available to bid. Leveraging the below chart we see prices recovering to the ~$150/MW-day level, albeit we would expect the bidding behaviors to shift such that the full price may not be realized (DYN would bid more into this auction).

Figure 13: IL Zone 4 2015-2016 Bidding Data



Source: MISO

Figure 14: MI Zone 7 2015-2016 Bidding Data



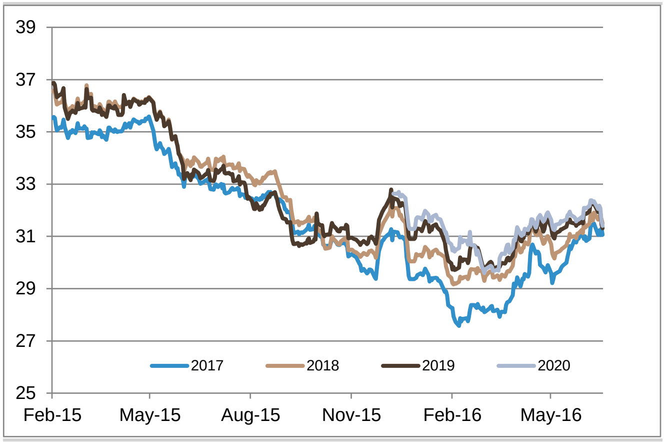
Source: MISO

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.*

What's the looming risk? Transmission.

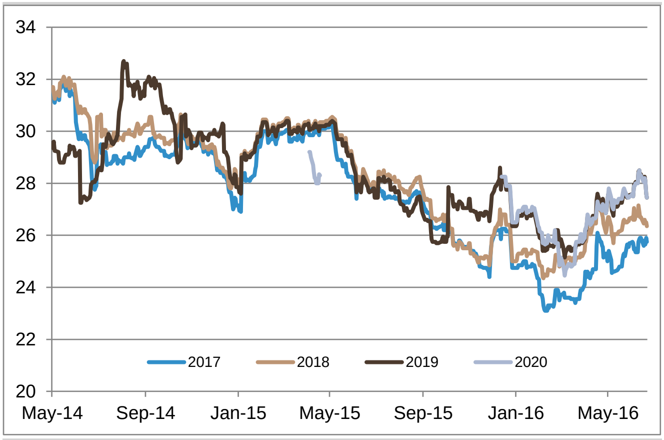
While the near-year improvements should provide some resiliency, we caution that forward procurements (3-year as contemplated under the MISO reforms) would bring the ongoing Ameren transmission upgrades to within the timeframe of the forward auction. As such, we see clear risk to the downside. Once more, we reiterate the exact definitions of *which* supply is able to participate will be critical as Zone 4 becomes largely de-constrained and part of the wider MISO North zone.

Figure 15: Indy Hub ATC Power Prices ($/MWh)



Source: Platts

Figure 16: Indy Hub Offpeak Power Prices ($/MWh)



Source: Platts

For further background we include links to recent reports below:

6/16/16: DYN: Simplifying the Art of the Deal
6/9/16: DYN: Commodity Rally Priced In: Downgrade to Neutral
5/4/16: Taking a Seat at the Negotiating Table
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

Figure 17: Sensitivity - $1/kW Change in Capacity Pricing - MISO

MISO Capacity Market Upside	DYN	NRG	NEE	CMS	ETR	EXC	D	CPN	Total
Nameplate Capacity (MW)	5,871	4,733	4,134	1,087	1,075	1,533	77	1,063	19,572
EFORd Adj. (MW)	5,539	4,235	2,006	1,025	984	1,099	8	1,003	15,899
Clearing Price in 2015/16 $/MW-Day	$ 150.00	$ 3.29	$ 3.29	$ 3.48	$ 3.29	$ 150.00	$ 3.48	$ 3.48	
Clearing Price in 2016/17 $/MW-Day	$ 72.00	$ 2.99	$ 2.99	$ 72.00	$ 2.99	$ 72.00	$ 72.00	$ 19.72	
YoY $/MW-day Sensitivity ($M)	**(158)**	**(0)**	**(0)**	**26**	**(0)**	**(31)**	**0**	**6**	**(158)**
Impact to EPS			**($ 0.00)**	**0.06**	**($ 0.00)**	**($ 0.02)**	**$ 0.00**		
2018 EPS or EBITDA	**$ 1119**	**$ 3113**	**$ 6.32**	**$ 2.02**	**$ 4.86**	**$ 2.57**	**$ 3.79**	**$ 1915**	
% of total 2017 UBS Estimate	**-14.1%**	**0.0%**	**0.0%**	**3.0%**	**0.0%**	**-0.9%**	**0.0%**	**0.3%**	

Source: Company Filings, PJM, SNL, and UBSe

New England: Running on Empty?

Risk of gas pipeline rejection bodes well for regional power prices

We see some near-term relief potentially from a clear risk for a gas pipeline to be rejected by the Mass SJC, which could effectively end for the time being gas pipeline expansions into the region as we would expect neighboring states to abandon their efforts.

The Massachusetts legislation – really about Hydro

Following the reintroduction of Senate Bill 1965, feedback from industry checks 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.

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

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

Proposals were submitted on Jan 28, however, we worry the solicitation could come later than its late July timeline (late summer?). 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. We see this as a smaller procurement effort ahead of a potentially larger effort next year.

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).

What are Key Elements of the Mass Legislation?

The bulk of the provisions are indeed constructive with a clear push for additional renewables, leaving ample procurement latitude for Northern Pass. We emphasize the Senate version authorizes the full 18TWh originally contemplated under the

first version of the bill, while the House version contemplates half ~9TWh. Both contemplate an incremental ~1.2GW of offshore wind.

We continue to expect the house and Senate to reconcile their respective bills in time for the July 31st clock. The harder climb has been achieved of passing legislation, and with Governor Baker firmly behind the effort still.

The Massachusetts legislation – running out of time

Mass bill could open the door to formal contracting for long-distance transmission from Canada

MA legislature has until July 31st, the end of this legislature period, to decide on the future role of renewables in their state as well as potentially parts of the entire Northeast. So far, both MA House and Senate have passed a renewable bill, H-4385 and S-2372 respectively, which could transform MA into a frontrunner in renewables integration. However, the gap between House and Senate bill is significant – and substantial compromises are necessary from the working group. A deal would then need to be re-ratified by each respective side by end of day on July 31.

The House bill, approved 154-1, plans for 1.2 GW of Canadian hydro and 1.2 GW of offshore wind with utility remuneration of a 2.75% rate of return attached to the legislation. Meanwhile, the Senate bill, passed unanimously, includes 2 GW of offshore wind and a provision for long-term clean energy contracts amounting to no more than 12,450,000 MWh. Moreover, the Senate bill includes a provision prohibiting electric utilities from passing along cost associated to gas projects, ie Access Northeast.

Given the differences between House and Senate bills, we expect a rather senior group of conferees to execute the negotiation process and develop the amended bill to be approved by both chambers and then ratified by the Governor. However, given that the conferees have yet to be appointed and that the national political conventions, RNC on July 17-20 and the DNC on July 24-27, are about to occur, we expect the conferee group to experience some time pressure during their process, which we repeat has a hard stop on July 31st.

While the offshore wind provisions were among the later items added to the bill in both chambers, we do not expect conferees to remove it from the final bill. In Sept 2015, offshore wind experienced a successful session in front of both chambers, arguing that they were not another Cape Wind and that costs reduction make offshore wind very attractive moving into the future. Instead, we expect the senate provision which requires home energy audits on all house sales as well as potentially the 2.75% rate of return to disappear before the final version.

Feedback from industry checks indicates a strong expectation for the renewables legislation to pass. 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. However, the legislative decision to bar electric utilities from doing gas deals could have significant negative impacts on Access Northeast prospects.

Seeing near-term recovery in gas price expectations

We suspect gas prices could continue to improve not just from the wider improvement in Henry Hub but also from the latest

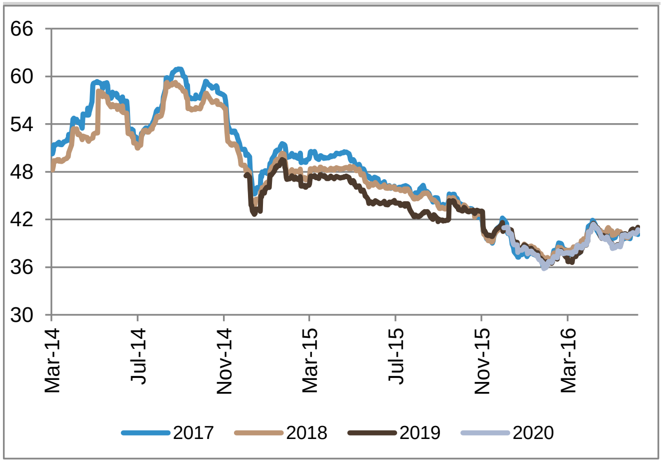
We see this accruing to Dominion: the key wildcard to the upside.

With the among most exposure- and certainly the greatest scrutiny to the New England energy market right now with its ~0% hedged on 2017 for Millstone, we see recovery in 2H16 in gas price (and power price) expectations for its nuclear plant as a key consideration. We see this as among the biggest positive wildcards in the near-term to stabilize EPS.

Another bite at the apple on the CT nuclear legislation?

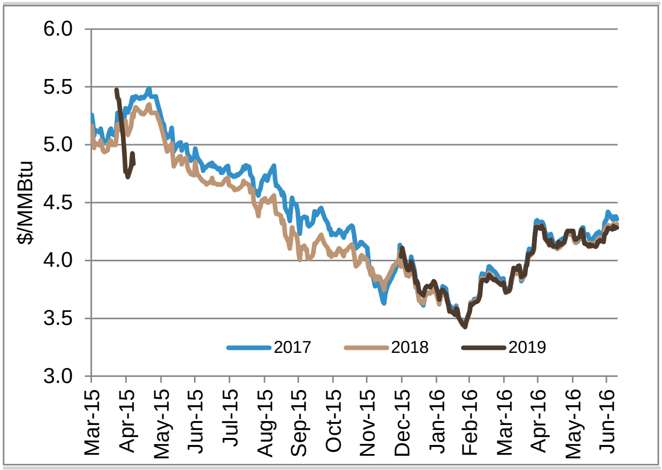
Further, we look for D to pursue another hard effort to get a program in place to effectively contract for a portion if not all of the Millstone unit. We emphasize our initial cut had estimated this as being worth ~$0.15-0.20 EPS, however would be tied to just how competitive an offer it would need to sell into a new state-specific zero-carbon procurement (vs. other renewables), likely in the $60's/MWh or lower. See more: *Giving New Life in New England*.

Figure 18: Mass Hub ATC Pricing ($/MWh)



Source: Platts

Figure 19: Algonquin Gas ($/MMBtu)



Source: Platts

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.

What about capacity prices? Expect downward pressure next auction

We continue to expect prices to be modestly down YoY given the litany of changes including in the demand curve design. We see pressure for prices to be in a range of ~$5.50-7.00/kW-mo. Still quite healthy vs adjacent regions, but declining off recent year highs. We suspect new-year EV/EBITDA multiples for IPPs will require all the more attention given the likely backwardated view on both capacity and power spark spreads (we focus our SOP on peak-ish 2018E EBITDA at present for instance, potentially contributing to caution on ascribing historic multiples across the sector of late).

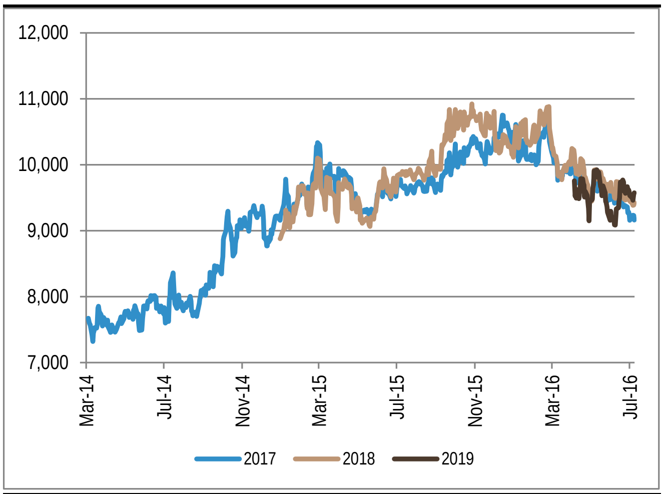
New Hampshire: divestments will likely drive retirements

…Just not there year. We emphasize the 439MW recently scrubbed coal plant Merrimack is quite likely to retire in Bow, NH upon divestment. In fact, it is not clear the plant will be 'divestable' in the process (the current deal with regulators actually addresses this pre-emptively). From a timing perspective, we would not expect a decision to tire *this auction* as the auction of the assets will have yet to take place (and hence don't want to assume no buyers/continued operations). We emphasize this is a clear retirement risk for the subsequent auction in ~2021/2022. We note elevated gas prices once more could yet breath new life into the asset and don't want to assume this shutdown as a forgone conclusion.

Focus from corporates remains on New England

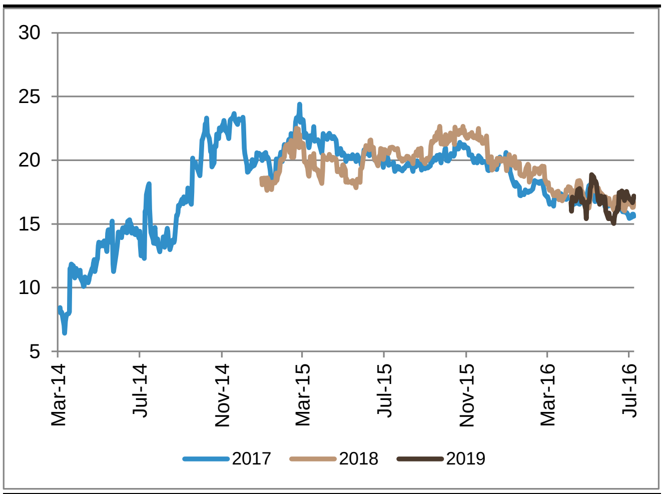
We see a relatively stable outlook for spark spreads in the high teens under the current outlook. We would expect the outlook to become increasingly backwardated as the timeline for new renewables reaching in-service out of both the smaller tri-state RFP and the subsequent likely MA RFP become clearer. It would appear to be more in the ~2019/2020 period.

Figure 20: Mass Hub Heat Rates (btu/KWh)



Source: Platts

Figure 21: Mass Hub Spark Spreads @ 7.2 ($/Mwh)



Source: Platts

For further background we include links to recent reports below:

5/11/16 ES: Just Passing Through, with Added Urgency

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?

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

Figure 22: Sensitivity - $1/kW Change in Capacity Pricing – ISO-NE

NE ISO Capacity Market Upside	CPN	DYN	D	EXC	NEE	NRG	PEG
Nameplate Capacity (MW)	2,193	2,435	2,576	2,777	2,042	2,988	1,161
EFORd Adj. (MW)	2,083	2,252	2,447	2,568	1,888	2,764	1,073
$1/kw-mo Sensitivity ($M)	25.0	27.0	29.4	30.8	22.7	33.2	12.9
Impact to EPS			0.03	0.02	0.03		0.02
2017 EPS or EBITDA	2,110	1,216	4.17	2.76	6.38	3,007	2.88
% of total 2017 Estimate	1.2%	2.2%	0.8%	0.8%	0.5%	1.1%	0.6%

Source: Company Filings, PJM, SNL, and UBSe

New York: Limiting the Carbon

We are increasingly concerned on prospects for this market

We see risk for power prices and capacity prices to see negative revisions as the NY PSC finalize their proposal for a Zero Emission Credit (ZEC) market by ~Aug 1st. We would expect a negative impact to both power prices (which had seemingly been volatile around these prices points previously) as well as negative to RGGI price expectations (which are currently under a model reset). RGGI implications include potential for other states to follow suit weighing on prices.

We also see NYISO Rest of State Capacity prices remaining relatively flat into 2017 now, see a ~$5/kW-mo outlook as more reasonably rather than the ~$8/kW-mo previously estimated. Further, without upside of future nuclear retirements this market is meaningfully less interesting, particularly when coupled with pending RPS implementation. This is most negative to **NRG** followed by **DYN**. This likely brings down the sale price expectation for Independence, pending a sale in the near term.

Figure 23: NYISO Capacity by Operator

NY Capacity (MW)	NRG	ETR	EXC	PEG	DYN	CPN	TLN
Rest of State	1,628	852	1,128	774	1,108	-	1,080
Lower Hudson Valley	758	2,069	-	-	-	-	-
New York City	1,366	-	-	-	-	121	-
Long Island	-	-	-	-	-	231	-
Total	**3,752**	**2,921**	**1,128**	**774**	**1,108**	**352**	**1,080**
Sensitivity to $1/kW-Month Change in Capacity Pricing							
Rest of State	20	10	14	9	13	-	13
Lower Hudson Valley	9	25	-	-	-	-	-
New York City	16	-	-	-	-	1	-
Long Island	-	-	-	-	-	3	-
Total	**45**	**35**	**14**	**9**	**13**	**4**	**13**
2017 UBSe EBITDA	2,944	3,999	6,486	4,481	1,162	2,163	708
% Change	**1.5%**	0.9%	0.2%	0.2%	**1.1%**	0.2%	**1.8%**

Source: SNL and UBS estimates

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 continues 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 28th)

What's the longer-term forecast for downstate? Limited constraints

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?:** We look for approval around ~August 1st of the latest effort to put 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.

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

- **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.

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.

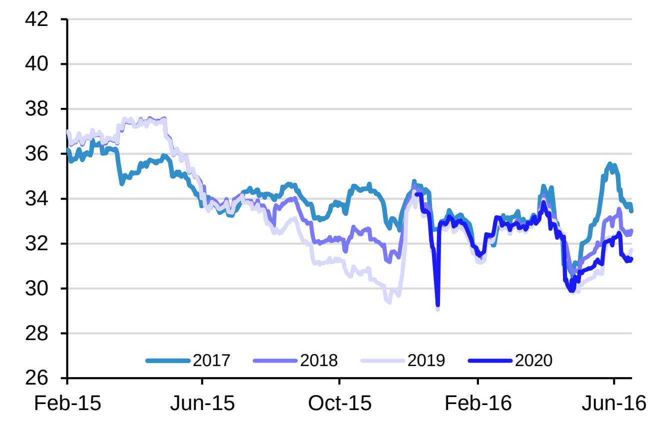
- **Gas imports into New York:** *not so much?* The wider question remains whether an effective replacement for the Constitution Pipeline will be found following its recent rejection. While near-term prospects for power have improved on the back of delayed or outright cancelled pipe efforts, they have been effectively swapped with longer-dated concerns for more renewables. Further, in the interim, nuclear retirements have been effectively put off the table; the market had been unclear on this prospect, but confirmation of retirements by ETR for instance of Fitz had largely been internalized into expectations.

- **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 MWs into this adjacent market. *The question remains at what price?*

Where are power prices trending? Forwards Punished

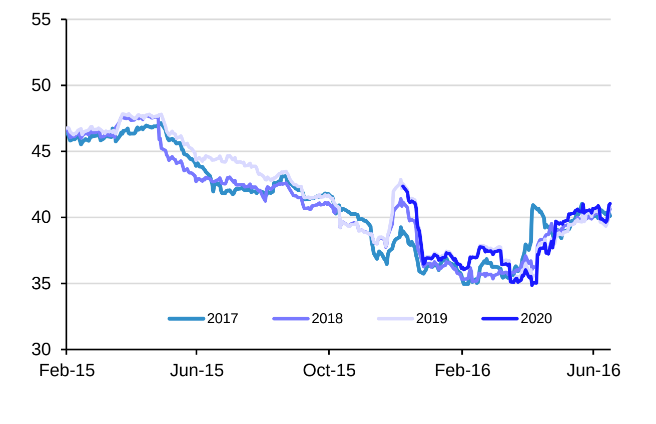
We include the latest Zone A (West), Zone G (Lower Hudson Valley) and Zone J (New York City) ATC prices to illustrate power price trends.

Figure 24: NY-Zone A ATC Power ($/MWh)



Source: Platts

Figure 25: NY-Zone G ATC Power ($/MWh)

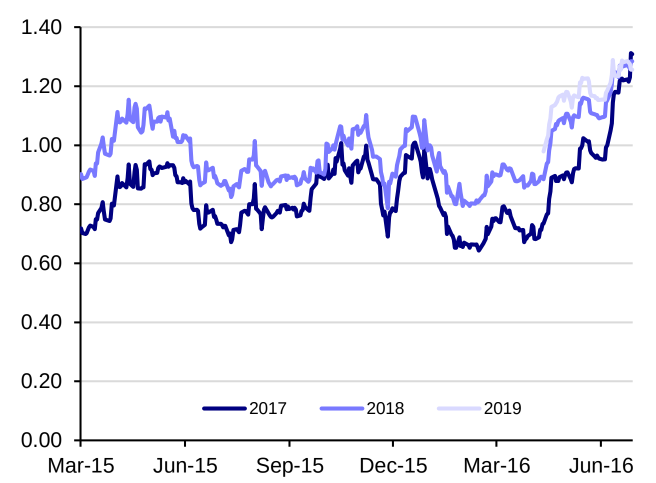


Source: Platts

Finally what about gas basis? Real improvement without the pipes.

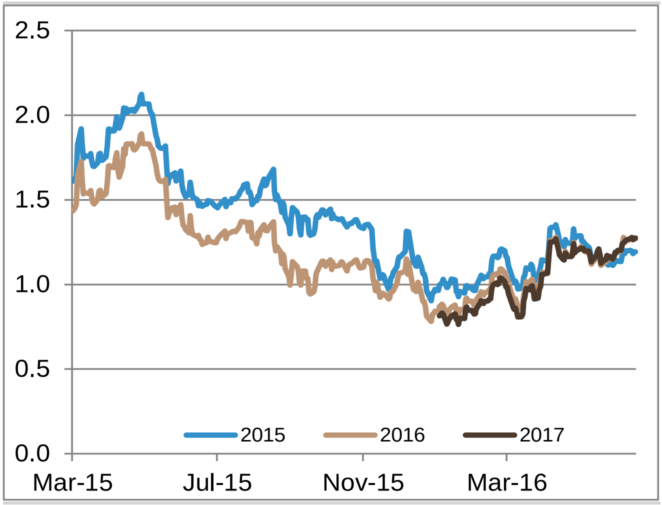
We include the Transco Zn 6 trends as well as Mass Hub price trends below. While muted vs. the highs, both have seemingly recovered in recent weeks as it has become clear the Constitution pipeline project will be delayed service into 2017.

Figure 26: Transco Zone 6 Gas Basis Swap ($/MMBtu)



Source: Platts

Figure 27: Algonquin Basis Swap ($/MMBtu)

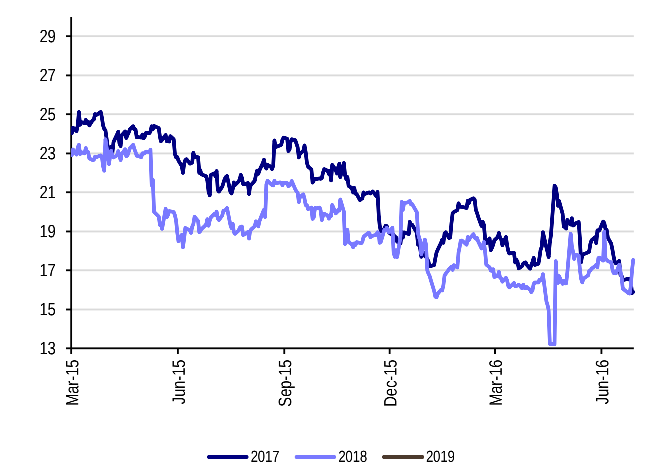


Source: Platts

And finally, what about sparks on gas assets? Downward.

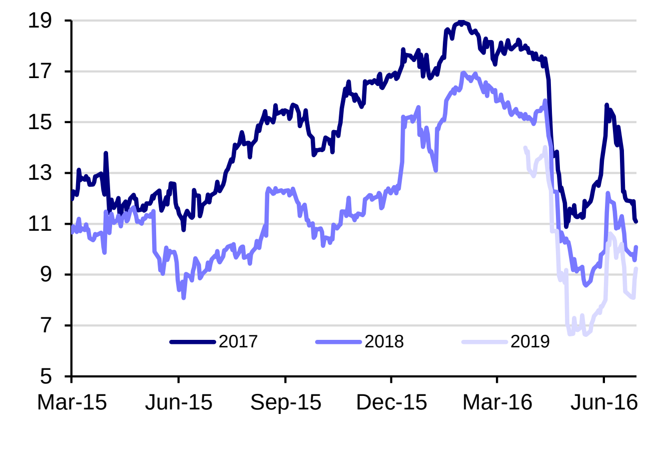
We also include the spark spread trends in each of these markets. We include principally sparks on the Zone G sparks, where most of the contemplated projects are contemplated at present.

Figure 28: Spark Spread: Zone G @ 7.2 heat rate (Dom South Gas) ($/MWh)



Source: Platts

Figure 29: Spark Spread: Zone A @ 7.2 heat rate (Transco Zone 6 Gas) ($/MWh)



Source: Platts

For further background we include links to recent reports below:

7/13/16: Setting the Tone on Nuclear

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

La Paloma is latest victim to weak California Power Markets Prices

2 CCGTs appear poised to close in the state.. many more are on the come.

In the latest case of Power Market distress, operators of the La Paloma facility have filed an emergency complaint at FERC against the CAISO which rejected the plants petition to pursue unit outages at 3 of the 4 CCGT units at the site. We emphasize the CAISO in this instance also rejected efforts to payout CPM payments or any other form of RMR to ensure the plant could meet its ongoing cash needs; CAISO emphasizes in its response to the complaint that the generator is free to retire, but rather cannot seek a long-duration outage as a mechanism for the retirement. Given the timing of July 1 through November 30, we suspect the rejection of the 206 complaint from FERC would lead to an immediate effort to formally retire, consistent with the process Calpine is pursuing in the case of Sutter. We emphasize the weak economics in the market remain among the worst of any regional market; we suspect other plants will follow the Sutter and La Paloma examples.

The exact reason behind why operators chose this retirement path for La Paloma is unclear, but potentially relates to legacy carbon AB32 credits. Further, a temporary outage through 4Q could enable the plant to pursue more of a seasonal dispatch approach if allowed to continue with such long duration outages.

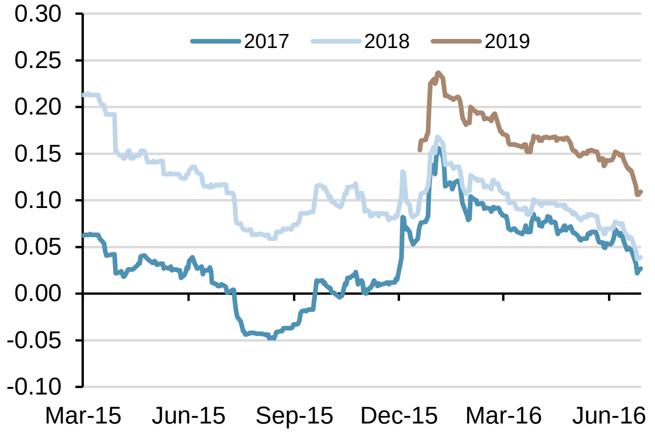
We think others could be shortly behind La Paloma and Sutter in pursuing similar efforts to exit the state. The question is not if, but rather the pace of such retirements. The further question is whether the CAISO will attempt to retain plants via RMR/CPM arrangements in light of the longer-dated retirement of Diablo Canyon. This is all in contrast to ongoing repowering efforts of Coastal units. We emphasize the plant has indeed been used historically and began commercial operations in 2003.

Link to the complaint: FERC Docket EL16-88.

Recovery prospects have moderated expectations for gas premium

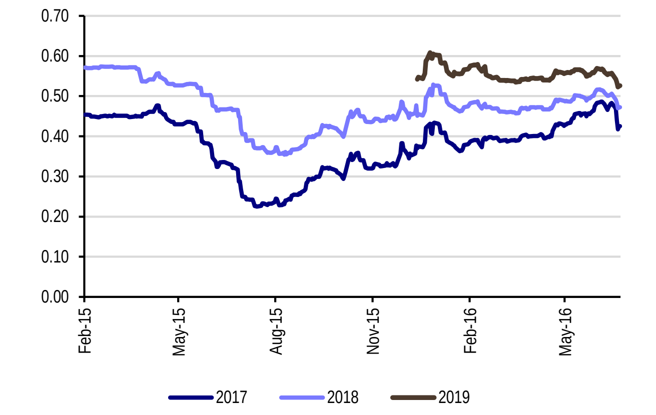
Although the leak that resulted from the blowout at the Aliso Canyon facility is plugged, Southern California Gas (SoCalGas – subsidiary of Sempra Energy), the operator of the facility, is prohibited "from injecting natural gas into the underground reservoir" until a safety inspection is completed, according 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 30: SoCalGas Gas Basis ($/MMBtu)



Source: Platts

Figure 31: PG&E City Gate Gas Basis ($/MMbtu)



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.*"

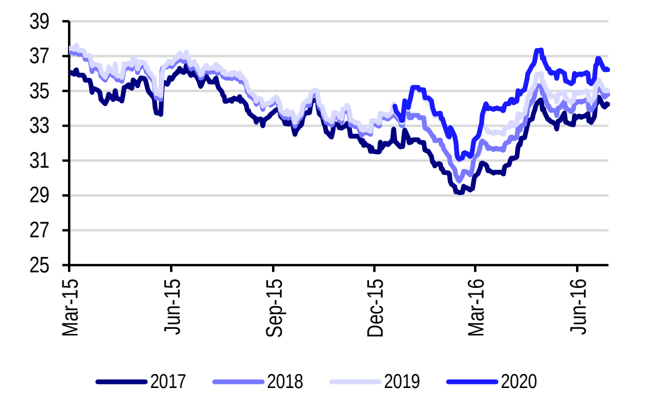
Latest gas leak in PG&E territory

We flag the latest at McDonald Island does not appear as substantial but warrants attention amidst a backdrop of substantial scrutiny of utility gas operations.

What about Power Prices? Resilient.

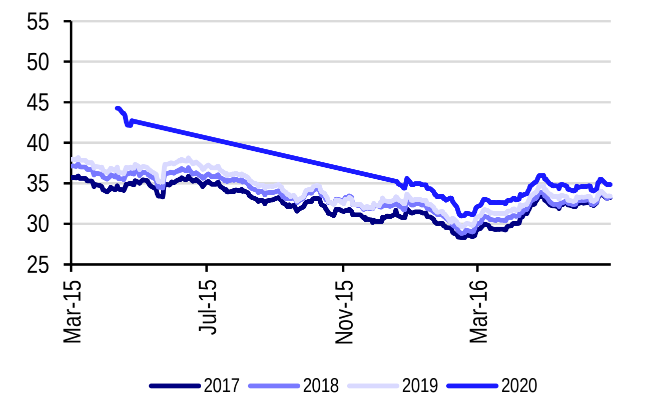
From this, we see power prices as having found a continued floor at current levels. We emphasize prices remains narrowly bunched as the 'marginal' unit remains unchanged throughout much of the period with the gas supply curve with CCGTs pervasive, quite flat.

Figure 32: NP15 ATC Power Prices ($/MWh)



Source: Platts

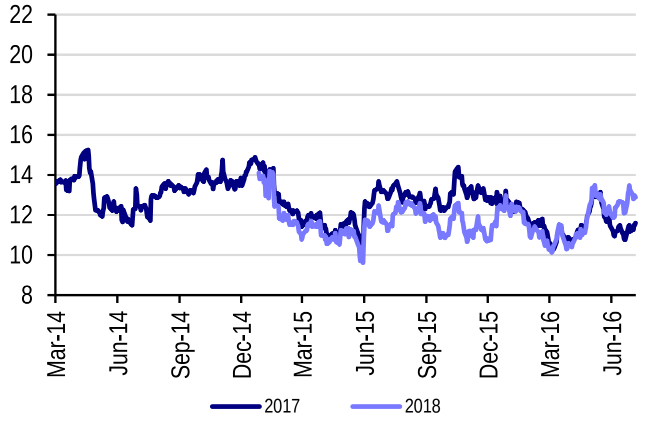
Figure 33: SP15 ATC Power Prices ($/MWh)



Source: Platts

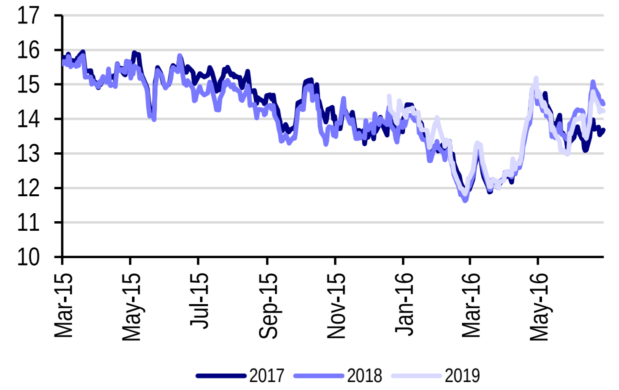
But Sparks have actually kept up of late. Relatively intact still despite gas price pressures. We remain relatively constructive in the near-term as plant retirements are a real prospect alongside higher gas tariffs priced into the market.

Figure 34: NP15 Spark Spread ($/MWh)



Source: Platts

Figure 35: SP15 Spark Spread ($/MWh)



Source: Platts

PG&E's Gas Rate Case: Unfavorable but past tense

We see significant risk of increase to dispatch costs

Yet another driver of power price inflation in the near term is the resolution of the 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 $0.35/MMBtu today to ~$1.35/MMBtu under the proposal). <u>We flag this has substantially impeded the economics for Dynegy's plant in the region and look for details with 2Q results.</u>

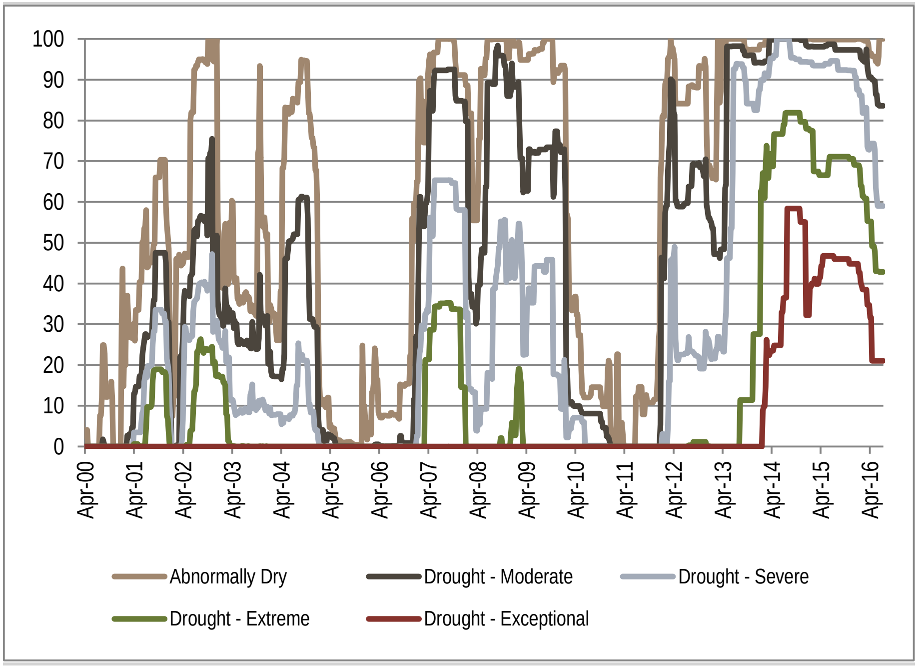
We note Calpine is also located in Northern California, largely with non-coastal, interior plants, not exposed to shifts in the pending GT&S case. In fact, the only plant that was materially exposed was Sutter, which was recently mothballed.

California's drought is substantially moderating

Easing drought conditions remain the primary headwind to power

We flag the drought has substantially improved in recent months, driving down both power and gas price expectations. We flag this is coincident with the La Nina conditions widely expected to follow a severe El Nino condition earlier.

Figure 36: 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 Sempra'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:

6/17/16: The Wild, Wild West
6/6/16: Breaking the Logjam in California?
6/2/16: Cruisin' our California Conference
4/18/16: Arguing the Case for California
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

Where's the UBS Gas Forecast?

Below we include commentary from our oil & gas colleagues from their July 6th note [please click here for the full report].

- **We are raising our 3Q16 and 4Q16 NYMEX natural gas price forecasts ($/MMBtu) to $2.80 and $3.00 (vs. $2.25 and $2.60 prior), respectively, increasing our FY16 forecast from $2.25/MMBtu to $2.45/MMBtu**. The upward revision is due to better than expected demand which has been driven by improved visibility from hot weather and increased coal-to-gas fuel switching from low prices through 2Q, both of which has left storage on track to start next winter at ~3.90 Tcf (~100 Bcf above normal but below the ~4.0 Tcf we were forecasting at the start of the injection season). Our revised 3Q and 4Q forecasts are above consensus ($2.33 and $2.50) but near the current futures strip ($2.81 and $2.98) as we believe some demand will be lost back to coal as prices rise have risen from ~$2/MMBtu in 1H16 to ~$2.90 for July bid week, partly offset by declining production from reduced drilling activity and infrastructure constraints in the northeast. We've left our 2017, 2018, and long-term normalized (2019+) price forecasts ($/MMBtu) unchanged at $3.00, $3.00, and $3.25, respectively.

We show below latest UBS forecast for US nat gas:

Figure 37: Revised UBS Oil and US Natural Gas Price Forecasts (2016-20E and Normalized)

	2014A	2015A	1Q16A	2Q16A	3Q16E	4Q16E	2016E	2017E	2018E	2019E	2020E	Normalized
WTI ($/Bbl)	**$92.89**	**$48.81**	**$33.64**	**$45.59**	**$47.00**	**$49.00**	**$43.81**	**$57.00**	**$67.00**	**$72.00**	**$72.00**	**$72.00**
Previous Estimate				*$38.00*	*$41.00*	*$46.00*	*$39.68*	*$52.00*	*$67.00*	*$72.00*	*$72.00*	*$72.00*
First Call Consensus					**$45.25**	**$50.00**	**$43.62**	**$54.00**	**$61.00**	**$66.50**	**$68.75**	**NA**
Futures Strip Price					**$47.53**	**$49.19**	**$43.99**	**$51.34**	**$53.32**	**$54.57**	**$55.65**	**NA**
UBS vs Consensus					4%	-2%	0%	6%	10%	8%	5%	NA
UBS vs Strip prices					*-1%*	*0%*	*0%*	*11%*	*26%*	*32%*	*29%*	*NA*
Brent ($/Bbl)	**$99.38**	**$53.57**	**$35.32**	**$47.41**	**$50.00**	**$52.00**	**$46.18**	**$60.00**	**$70.00**	**$75.00**	**$75.00**	**$75.00**
Previous Estimate				*$41.00*	*$44.00*	*$49.00*	*$42.35*	*$55.00*	*$70.00*	*$75.00*	*$75.00*	*$75.00*
First Call Consensus					**$47.00**	**$50.00**	**$45.07**	**$56.00**	**$64.00**	**$69.00**	**$70.00**	**NA**
Futures Strip Price					**$48.59**	**$50.05**	**$45.48**	**$52.51**	**$55.22**	**$57.25**	**$59.16**	**NA**
UBS vs Consensus					6%	4%	2%	7%	9%	9%	7%	NA
UBS vs Strip prices					*3%*	*4%*	*2%*	*14%*	*27%*	*31%*	*27%*	*NA*
Natural Gas NYMEX ($/MMBtu)	**$4.45**	**$2.67**	**$2.09**	**$1.95**	**$2.80**	**$3.00**	**$2.45**	**$3.00**	**$3.00**	**$3.25**	**$3.25**	**$3.25**
Previous Estimate				*$2.00*	*$2.25*	*$2.60*	*$2.25*	*$3.00*	*$3.00*	*$3.25*	*$3.25*	*$3.25*
First Call Consensus					**$2.33**	**$2.50**	**$2.22**	**$2.89**	**$3.00**	**$3.01**	**$3.01**	**NA**
Futures Strip Price					**$2.81**	**$2.98**	**$2.46**	**$3.15**	**$3.03**	**$3.02**	**$3.06**	**NA**
UBS vs Consensus					20%	20%	10%	4%	0%	8%	8%	NA
UBS vs Strip prices					*0%*	*1%*	*0%*	*-5%*	*-1%*	*8%*	*6%*	*NA*

Source: UBS estimates, FactSet, and Bloomberg

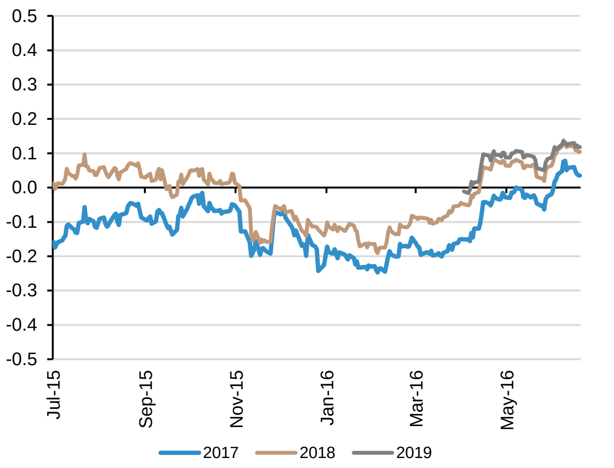
What about Gas Basis Trends of Late?

Dominion-South and TETCO

Gas basis little changed for either TETCO or Dominion South in recent months. Given delays in pipelines TETCO prices are improving of late. We suspect prices will continue to improve as other contemplated New York and New England projects potentially face headwinds.

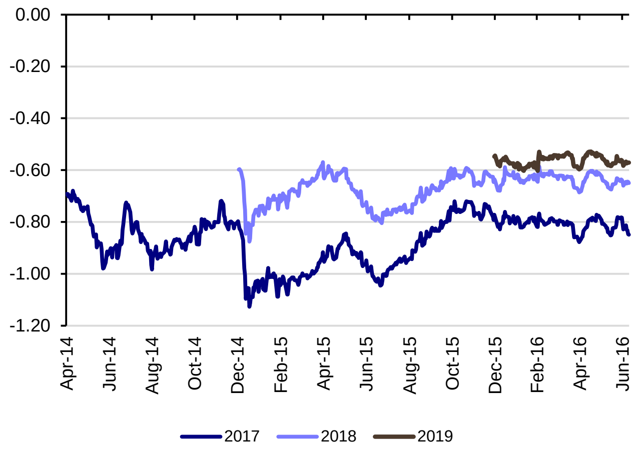
Despite delays in pipelines (and hence concerns of limited takeaway capacity), Dom-South has failed to deteriorate in recent months,

Figure 38: TETCO M3 Basis Swap ($/mmbtu)



Source: Platts

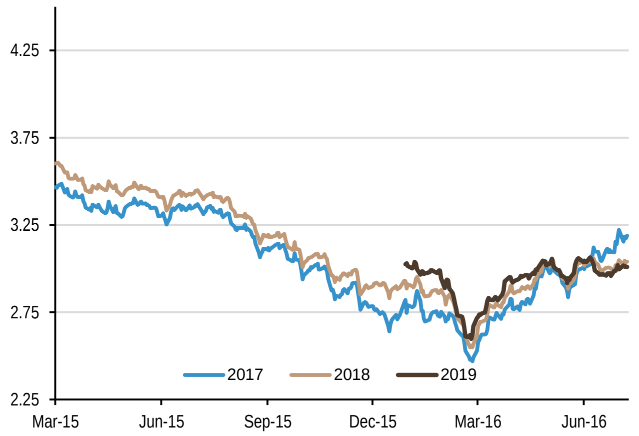
Figure 39: Dominion South Basis Swap ($/mmbtu)



Source: Platts

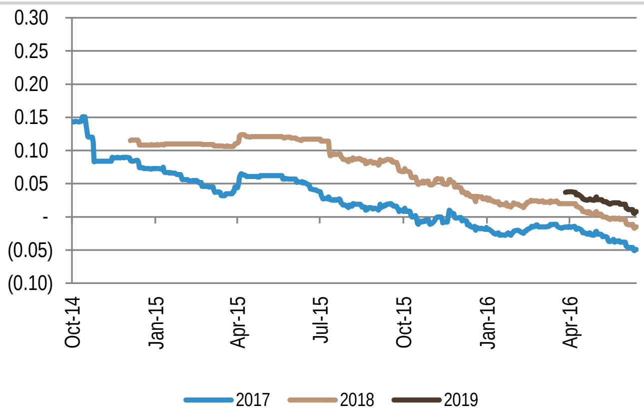
Henry Hub has stabilized in recent weeks while the Houston ship channel basis continues to decline. We suspect declines in Houston Ship to be attributable to growingx regional Supply expectations once more.

Figure 40: Henry Hub ($/mmbtu)



Source: Factset

Figure 41: Houston Ship Channel Swap Basis ($/mmbtu)



Source: Platts

Where did spot prices trend?

We include actual spot prices across several key markets below for 2Q, which shows some improvement from 1Q but substantial declines on a YoY basis.

Figure 42: Peak Spot Power Prices

Power Price $/MWh Quarter End	PJM West	PJM East	CAISO	ERCOT	MISO Indiana	MISO Illinois	NEISO	NYISO
6/30/2016	32.9	28.8	27.3	21.3	32.0	28.6	28.2	28.4
3/31/2016	29.6	31.4	23.9	19.0	31.4	25.9	29.4	29.3
12/31/2015	30.6	28.5	31.5	21.1	37.3	25.6	30.5	25.0
9/30/2015	38.1	40.5	40.1	33.0	38.1	32.0	38.5	36.6
6/30/2015	37.7	37.1	25.7	27.2	37.0	29.7	29.0	32.8
3/31/2015	57.3	67.4	32.3	26.5	44.4	31.9	87.0	78.3
12/31/2014	39.9	48.3	43.0	33.6	58.9	35.6	46.1	41.4
9/30/2014	41.6	45.4	49.7	37.1	35.2	36.4	40.7	40.1
6/30/2014	48.3	51.5	45.6	41.0	37.9	46.1	42.9	44.0
6/30/2016 vs 6/30/2015	**-13%**	**-22%**	**6%**	**-22%**	**-14%**	**-4%**	**-3%**	**-13%**

Source: Bloomberg

Nat Gas was rising, but sparks proved resilient

PJM east was the only exception to the overall upward trend QoQ, albeit off a very low base in Q1 and generally down YoY spark spreads. CAISO showed substantial improvement in the quarter, however

Figure 43: Qtr Avg Spark Spreads @7.2 Heat Rate

7.2 HR Spark Spread $/MWh Quarter End	PJM West	PJM East	CAISO	ERCOT	NEISO	NYISO
6/30/2016	21.7	17.6	11.5	6.5	12.1	16.3
3/31/2016	16.7	18.5	8.0	5.2	11.9	10.7
12/31/2015	21.5	19.4	12.0	6.0	8.4	11.4
9/30/2015	28.5	31.0	17.5	13.4	21.8	21.0
6/30/2015	26.4	25.8	3.7	7.8	13.1	15.1
3/31/2015	16.5	26.5	10.3	6.7	2.5	15.5
12/31/2014	20.6	29.0	12.8	7.3	8.3	19.0
9/30/2014	24.3	28.1	16.9	8.6	19.0	22.4
6/30/2014	22.4	25.5	9.2	8.2	12.5	17.9
6/30/2016 vs 6/30/2015	**-18%**	**-32%**	**212%**	**-17%**	**-8%**	**8%**

Source: Bloomberg

Forward ATC Heat Rates

We include the latest forward heat rate outlook by market.

Figure 44: Forward ATC Heat Rates (MWh/MMBtu) by Power Market

	2016	2017	2018	2019
NP15 / PG&E	11.65	10.43	10.86	10.65
YoY % Change		-10.4%	4.1%	-2.0%
ERCOT-S/Houston Shipping	12.44	12.38	12.84	12.51
YoY % Change		-0.6%	3.8%	-2.6%
NYISO Zn G / Transco Zn 6	15.16	10.75	11.25	10.87
YoY % Change		-29.1%	4.6%	-3.4%
Southern / Transco Zn 4	11.44	10.55	10.55	10.05
YoY % Change		-7.8%	0.0%	-4.7%
Mass Hub / Algonquin	11.10	10.87	11.01	10.95
YoY % Change		-2.1%	1.3%	-0.5%
Entergy / Henry Hub			11.97	11.77
YoY % Change				-1.7%
NI Hub / Chicago Citygate	13.46	11.27	12.03	11.16
YoY % Change		-16.3%	6.8%	-7.2%
PJM West / TETCO M3	19.44	12.82	12.53	12.01
YoY % Change		-34.1%	-2.2%	-4.2%
AD Hub / MichCon	14.46	11.71	12.34	11.46
YoY % Change		-19.1%	5.4%	-7.1%
ERCOT-Houston/Houston Ship	12.79	12.74	12.91	12.70
YoY % Change		-0.3%	1.3%	-1.6%
ERCOT-West/Houston Ship	11.88	11.96	12.28	11.94
YoY % Change		0.7%	2.7%	-2.7%
ERCOT-North/Houston Ship	12.06	12.05	12.35	12.15
YoY % Change		-0.1%	2.4%	-1.6%
CIN-Hub/ Chicago Citygate	13.37	11.64	12.31	11.20
YoY % Change		-12.9%	5.7%	-9.0%
Average		*-11.0%*	*3.0%*	*-3.7%*
1Q16 Average		*-7.1%*	*-2.1%*	*-2.6%*
4Q15 Average		*-8.6%*	*-2.4%*	*1.5%*
3Q15 Average		*-3.7%*	*-5.5%*	*1.5%*
2Q15 Average		*-2.6%*	*-2.4%*	*1.3%*
1Q15 Average		*-3.5%*	*-2.7%*	*1.3%*

Source: Platts, UBSe

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 45: ATC Heat Rates – Change YoY for Forward 2017 (btu/Kwh)

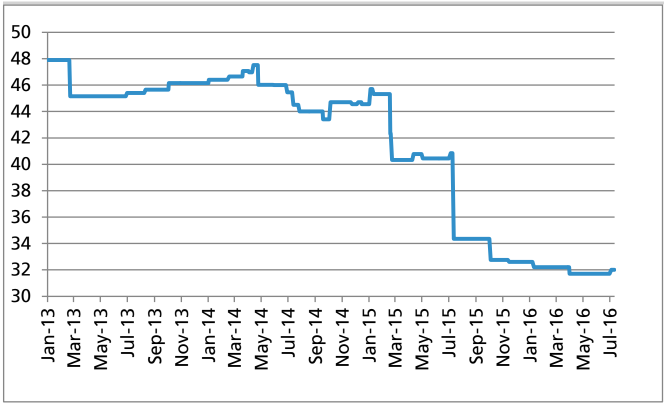
ATC Heat Rates 2017					
	ERCOT-North	ERCOT-Houston	ERCOT-West	ERCOT-S	Southern
Jul-16	9,625	10,317	9,414	9,845	9,273
Jul-15	9,201	9,963	8,987	9,410	9,428
YoY % Change	5%	4%	5%	5%	-2%
	NY-ZnG	NY-ZnJ	NY-ZnA	MassHub	
Jul-16	8,968	9,630	10,085	9,269	
Jul-15	10,394	10,982	10,212	9,667	
YoY % Change	-14%	-12%	-1%	-4%	
	PaloVerde	SP15	NP15	MidC	
Jul-16	12,035	10,859	9,537	7,903	
Jul-15	11,323	10,531	9,692	8,194	
YoY % Change	6%	3%	-2%	-4%	
	Indy Hub	NI Hub	ADHub	PJM-W	
Jul-16	9,801	9,199	9,965	10,704	
Jul-15	10,295	9,398	10,651	11,460	
YoY % Change	-5%	-2%	-6%	-7%	

Source: Platts, Bloomberg

Coal Price Trends

Coal prices remain weak, however, could well see a recovery in pricing as the inventory backlog is addressed. Please see our wider note from yesterday.

Figure 46: Illinois basin coal prices



Source: Bloomberg

Figure 47: PRB coal prices

Source: Factset

Capacity Price 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 48: Capacity Market Projections by Region

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
PJM ($MW-day)													
RTO	111.9	102.0	174.3	110.0	16.5	27.7	126.0	136.0	134.0	151.5	164.8	100.0	125.0
EMAAC	148.8	191.3	174.3	110.0	139.7	245.0	136.5	167.5	134.0	151.5	225.4	119.8	144.8
SWMAAC	210.1	237.3	174.3	110.0	133.4	226.2	136.5	167.5	134.0	151.5	164.8	100.0	125.0
MAAC				110.0	133.4	226.2	136.5	167.5	134.0	151.5	164.8	100.0	125.0
DPL-S			186.1	110.0	222.3	245.0	136.5	167.5	134.0	151.5	225.4	119.8	144.8
PS-N					185.0	245.0	225.0	167.5	134.0	151.5	225.4	119.8	144.8
PSEG					139.7	245.0	136.5	167.5	134.0	151.5	225.4	119.8	144.8
PEPCO						247.1	136.5	167.5	134.0	151.5	164.8	100.0	125.0
ATSI								357.0	134.0	151.5	164.8	100.0	125.0
ComEd						27.7	126.0	136.0	134.0	151.5	215.0	202.8	202.8
PPL						226.2	136.5	167.5	134.0	151.5	164.8	100.0	125.0
ISO-NE													
Annualized ($/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	7.03
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	7.03
NYISO - Zn J													
Summer ICAP ($/kW-month)	6.50	6.75	12.90	13.54	11.70	14.80	16.24	15.50	10.00	10.00	11.00	11.00	11.00
Winter ICAP ($/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	6.67
NYISO Zn J ($/kW-month)	4.35	5.08	8.77	8.75	7.50	10.16	12.04	11.68	8.34	8.34	8.84	8.84	7.72
NYISO Zn J ($/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	92.68
NYISO - RoS													
Summer ICAP ($/kW-month)	2.67	3.01	2.47	0.55	1.25	5.80	5.15	3.50	4.25	4.96	5.00	5.00	5.00
Winter ICAP ($/kW-month)	1.91	1.77	1.75	0.39	0.15	0.82	2.58	2.90	2.35	2.35	2.35	2.35	2.35
NYISO - RoS ($/kW-month)	2.27	2.39	1.88	0.43	0.81	2.80	3.92	3.11	3.30	3.65	3.67	3.67	3.28
NYISO - RoS ($/kW-yr)	27.20	28.64	22.60	5.16	9.74	33.64	47.02	37.29	39.57	43.85	44.07	44.07	39.38
NYISO - LHV													
Downside case - assumption	2.67	3.01	2.47	0.55	1.25	4.20	5.15	3.50	3.62	4.96	5.00	5.00	5.00
Winter ICAP ($/kW-month)	1.91	1.77	1.75	0.39	0.15	0.82	2.58	2.90	1.25	2.35	2.35	2.35	2.35
NYISO - RoS ($/kW-month)	2.27	2.39	1.88	0.43	0.81	2.80	3.92	2.93	2.62	3.65	3.67	3.67	3.28
NYISO - RoS ($/kW-yr)	27.2	28.64	22.6	5.16	9.74	33.64	47.02	35.10	31.41	43.85	44.07	44.07	39.38
MISO Capacity Values:													
IPA Auctions ($/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	72.00	72.00	72.00	72.00
Calendarized ($/KW-yr)							3.73	34.48	38.14	26.28	26.28	26.28	26.28

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

Power Market Preferences

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 *real* market we have confidence in medium-term improvement

We continue to prefer ERCOT, *albeit remain cautious on the long term across all US Power markets.* 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. We increasingly see NYISO as the most concerning give the twin impacts of Zero Emission Credits (ZECs) keeping nuclear and forthcoming 50% RPS.

We are raising MISO to reflect our expectations for an improving trend on capacity prices out of its pending reforms. We emphasize recovery given the Clinton nuclear plant retirement appears to be coming on the margin

We are maintaining ISO-NE, although we see the forthcoming Mass legislation risk as a clear potential downside given the size of the potential RFPs out of the state, accounting for ~30-40% of total new renewables procured. We emphasize capacity prices are trending lower, albeit have more limited structural downside given existing rules.

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.

Figure 49: Power Market Preferences

UBS Preferred Power Market List - Rank Order				
Preference	*New Rank*	*Old Rank*	*Market*	*Reasoning*
Most Preferred	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	3	PJM	*Reforms largely reflected-- support on capacity offset by continued new gas entry*
	4	6	MISO	*Combo of low-cost wind and challenging market construct. Potential DYN/EXC retirements will be key*
	5	5	CAISO	*Increasing gas prices from Aliso Canyon leak and GT&S rate case should help in near-term*
Least Preferred	6	4	NYISO	*We see new gas and new supply as driving down capacity prices*

Source: USB Estimates

Talen Energy Corp.

The 'go-shop' period expired on July 12th without a superior proposal and now management's focus is on completing the necessary regulatory filings to facilitate closing the transaction by YE16.

TLN intends to host a 2Q16 earnings call at this time.

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

6/3/16 Riverstone Steps In
5/12/16 Shifting the Capital Allocation Timeline
4/25/16 How Much Room is Left?
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 key updates for TLN?

- **No superior offers received:** On July 12th Talen disclosed in a 14A filing that it did not receive a superior offer during the 40-day 'go-shop' period and is moving forward with the $14/sh Riverstone transaction announced on June 3rd. The NRC change of control filing was made in late June with the FERC and other regulatory filings expected in July/August.

At the $14/sh offer price the offer price the implied 2018 EV/EBITDA multiple is ~8x UBSe (7.6x Consensus), representing a strong premium over where peers Dynegy (6.6x) and NRG Energy (6.3x) were trading at the time.

- **We continue to believe that shareholders will approve the transaction:** The scenario under which a deal might not be approved is if commodities rallied prior to shareholder approval date such that the bid was no longer commensurate with the market environment. We do not believe there is an analogy to Blackstone's previous bid for Dynegy in 2010 in which shareholders launched a campaign to rebuff the perceived low bid for the company. We emphasize the PPL/Riverstone received regulatory approvals in 2014/2015 for the merger (approximately year ago). The shareholder votes will be held when the proxy statement is finalized.

We believe there is a low probability that shareholders reject the proposal.

- **Colstrip settlement achieved:** Talen and the other joint owners reached a proposed settlement to release liability and lead to retirement of Units 1 & 2 by 2022 with the dismissal of Units 3 & 4 claims. Talen owns 50% of Units 1 & 2 and 15% of Units 3 & 4 through an agreement with NorthWestern. Talen has stated that the Western asset is non-core and is open to exploring alternative ownership agreements.

- **Best Harquahala risk/reward likely involves finding a local solution:** Management has stated that it 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 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.

  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.

  Further details on the desert Southwest market are available below:
  6/17/16 The Wild, Wild West
  7/11/16 Can Utilities Avoid A Summer Swoon?

We're biased to believe the asset is able to get a contract – rather than moving

Management has previously indicated it would address the future of this plant in 2016E

It would appear the cost of transporting the plant could approach ~$350/kW

Valuation: Maintain $14 Price Target

Our valuation methodology continues to be based on the Riverstone offer price.

Dynegy Inc.

Following the latest capacity auctions the attention is now on the potential asset sales that management has discussed and the synergy update for Engie. We caution that sales prices could disappoint on a $/kW basis for CA and NY.

Look for weaker 2Q results

We forecast Dynegy reporting 2Q16 adjusted EBITDA of **$177Mn**, behind Street expectations ($242Mn). We flag 2Q estimates reflect the first year of full year contributions from the prior ECP and Duke acquisitions. We see prices trending lower YoY primarily from lower dark spreads as well as milder Northeast sparks.

Figure 50: DYN 2Q16E Adj EBITDA Walk

Dynegy ($Mn)	2Q16E	2Q15A	YoY	Notes
Consensus EBITDA	*$242*			
Adj. EBITDA UBSe	177	193		
Corp & Other	(30)	(33)	*3*	*Similar trend of ~$30Mn, slightly higher YoY*
IPH	5	5	-	*Energy Margins offset by improving Capacity*
CoalCo	20	19	*1*	*Energy Margins offset by improving Capacity*
GasCo	182	202	*(20)*	*Lower Spark Spreads & Hedges Rolling*

Source: Company reports, ThomsonReuters, UBS estimates

Updated EBITDA Estimates

We reflect the latest commodity MtM outlook, seeing estimates at the bottom-end of the range for 2016E. We currently estimate $3.6Bn of cumulative 2016-2018E EBITDA versus the $3.9Bn 2016E-2018E guidance provided at the 2015 Analyst Day last summer. Our estimates are tweaked higher on account of recent MtM improvements, consistent with recent share price recovery. We offset this with a negative impact from a ~350MW outage at one of the Hanging Rock CCGT units as well as the assumed retirement of the Coleto Creek asset in Texas.

Figure 51: Pro-Forma Forward EBITDA Estimates for DYN

Dynegy EBITDA Breakdown (UBSe)	2014A	2015A	2016E	2017E	2018E	2019E
Midwest	92	53	110	105	147	115
West	62	80	61	16	26	20
Northeast	187	163	141	135	154	155
Illinois Power Holdings	78	76	74	159	169	128
Duke Midwest	0	240	298	220	300	222
Energy Capital Partners	0	253	332	373	445	392
PRIDE Reloaded & Other Synergies	0	115	233	265	290	290
Consolidated G&A and Other	(72)	(130)	(130)	(130)	(130)	(130)
Recurring Adjusted EBITDA	**347**	**850**	**1,119**	**1,143**	**1,401**	**1,192**
Previous		***850***	***1,119***	***1,162***	***1,388***	***1,175***
Consensus (6/15/2016)	**$364**	**$880**	**$1,101**	**$1,263**	**$1,398**	**$1,138**
Engie JV (100%)			***$451***	***$453***	***$566***	***$486***
Mgmt Guidance: Adj EBITDA	**$300-$350**	**$825-$925**	**$1.0-$1.2Bn**	**~$1,300**	**~$1,300**	
Capital Spending	**-$160**	**-$285**				
Cash Interest	**-$145**	**-$425**				
Other Cash Impacts	**$15**	**-$15**				
Free Cash Flows	**$10-$60**	**$140-$240**	**$200-$400**	**~$500**	**~$500**	

Source: Company reports, USB estimates

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

[6/16/16: Simplifying the Art of the Deal]
[6/9/16: Commodity Rally Priced In: Downgrade to Neutral]
[5/4/16: Taking a Seat at the Negotiating Table]
[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 are the key updates for DYN?

- **Getting clarity on reforms in MISO:** We look for datapoints on the MISO reform process, which is scheduled to provide updated throughout July and August ahead of a late August filing before the FERC for capacity auction reforms. Our expectations for pricing improvement in the market remain modest and caution that the scenario analysis released by MISO and the market monitor may not fully materialize. Bottom line, we perceive wider skepticism from a variety of constituents including management here. The focus will remain on finding a way to export more capacity into PJM.

- **IPH restructuring underway:** Mgmt remains in negotiations with creditors. Given anticipated retirements, DYN is keen to restructure debt proactively ahead of its maturity in 2017. The $825 Mn trades at $320Mn in market value. A further nuance could include the contribution of *existing* assets to IPH ring-fence for the debt following previously management statements but it is unclear how much value that would provide (seemingly minimal). Dynegy's 1Q16 presentation substantially reduced FCF expectations at this subsidiary given the potential re-assignment of value at this subsidiary back to Dynegy given the marketing arrangements in place.

Addressing IPH remains the top priority for this year

Debt is trading at ~40¢ of late, or ~$320Mn in market value vs. $825Mn par value

What's the market value today?

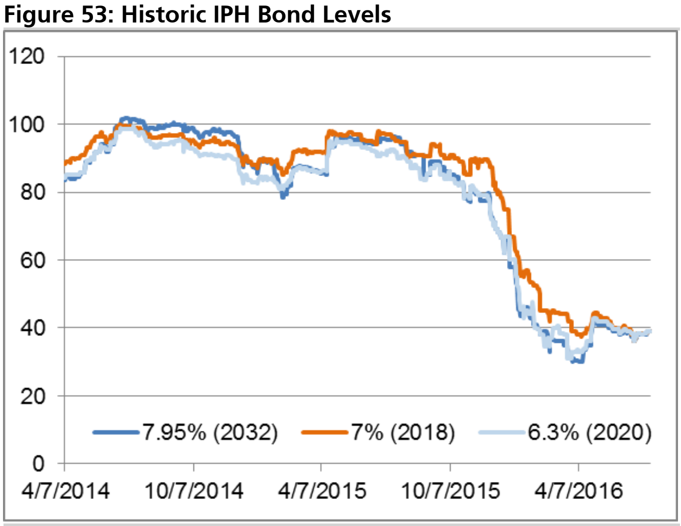
The IPH bonds imply a pricey ~$125/kW for the remaining (2) coal plants assuming the Newton plant is retired. We would not expect management to offer to take in the structure at the current valuation, seeing limited value, particularly without the marketing enterprise behind DYN.

Figure 52: FMV of IPH Bonds ($Mn)

Analysis of IPH Bond Valuation ($Mn)			
Notes	Fair Mkt Value	Book Value	
2032	107.3	275.0	39%
2018	117.0	300.0	39%
2020	97.5	250.0	39%
	321.8	825.0	39%

Source: FactSet

Figure 53: Historic IPH Bond Levels



Source: FactSet

But is there value at the subsidiary? Unlikely given the debt

While we do not see value today in the segment even at the $320Mn mark-to-market of debt, 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 stand-alone basis, with the remaining assets operating at seemingly breakeven FCF levels (at best).

More asset sales have been discussed by management:

DYN appears poised to divest additional assets in effort to continue to reduce leverage and re-allocate resources

We look for sale price expectations to continue to trend lower as IPPs transact in the lower spark and capacity price environment. We include our latest expectations on this sale following the negative PG&E GT&S auction outcome.

- **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).

  The unfavorable alternative proposed decision of the latest PG&E GTS&S case added $10-15 Mn/yr in costs to the portfolio, substantially reducing the EBITDA and FCF profile of its assets. It appears to have added nearly ~$1/MMBtu, driving rates up to nearly ~$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.

We see a risk the Dynegy portfolio could garner some attention as a meaningfully negative implied $/kW value, as well as a headline low value for the core of the portfolio, the 1GW CCGT, Moss 1&2, potentially at ~$100/kW or lower.

Figure 54: California Portfolio Potential Value

Dynegy California Portfolio Potential Transaction Value							
Asset	Location	Fuel	MW	$/kW	Value ($Mn)	EBITDA	Implied EV/EBITDA
Moss Landing							
Units 1-2	Monterey County	Gas CCGT	1,020	80	$82	$8	9.9x
Units 6-7	Monterey County	Gas	1,509	-	-	N/A	N/A
Oakland	Oakland	Oil	165	30	5	N/A	N/A
Morro Bay*	Morrow Bay	N/A	650	8	5	N/A	N/A
* Transmission Capacity		Total	2,694	*34*	$92		
		Total per Sh			$0.58		
Est. Rate of Delivered Gas	*↑ Potential W./ GTS Case: $1/Mmi*			***NPV***	***~$200Mn***		

Source: Company Filings and UBS Estimates

We include our best estimate of the EBITDA profile of this asset under the gas tariff.

What are the new economics of the Moss Landing 1&2 CCGT?

Figure 55: Moss Landing 1&2 – Estimated new EBITDA profile

CCGT - Moss Landing 1&2	2014A	2015A	2016E	2017E	2018E
Revenue	187	125	91	94	96
Moss Landing CC	4.1	3.4	2.9	3.1	3.1
Capacity	1,020	1,020	1,020	1,020	1,020
Capacity Factor	46%	38%	33%	35%	35%
NP15 Onpeak ($/MWh)	47	40	34	37	38
PG&E LDC Adder ($/Mmbtu)				0.69	0.69
PG&E Citygate ($/MMBtu)	5	3	3	4	4
Spark Spread - NP15	10	14	8	2	3
Carbon Cost ($/t)	12	12	12	12	12
Gross Margin (Spark)	42	47	24	6	10
Premium to Peak	10%	10%	10%	10%	10%
Fuel Cost	145	77	67	88	86
O&M	26	26	26	26	26
O&M ($/MWh)	5	5	5	5	5
O&M ($/kW-yr)	25	25	25	25	25
Energy EBITDA	16	22	-1	-19	-15
Capacity on 1&2	693	750	750	750	1020
Capacity/Tolling Payments	9	17	17	17	24
Tolling Agreements ($/KW-yr)	14	23	23	23	23
EBITDA with Capacity	**26**	**39**	**16**	**-2**	**8**

Source: Company reports and UBS estimates

What about New York: Independence prospects reduced: On the heels of its Engie deal, we continue to look for datapoints on the potential sale of its 1.2GW Independence CCGT. While expectations had been climbing higher towards $600/kW or better, the question is how substantial upstate New York power market expectations have been negatively impacted by the latest offer from the NY PSC to extend 'Zero Emission Credits' (ZECs) to nuclear units upstate. This has been the key wildcard to not just capacity markets (where we estimate a ~$30Mn/yr swing in future EBITDA expectations) as well as power price expectations (alongside RGGI price expectations, which also eventually are reflected in the power price as well). Further, with the NY PSC poised to provide an updated view by month on its latest track in REV on Renewables, we suspect RPS datapoints could also moderate expectations. That said, Dynegy knew of these potential forthcoming potential pressures in pursuing the sale and see the calculated decision to de-emphasize this market as illustrative of these wider concerns. We estimate ~$90-100 Mn in annualized EBITDA from this asset, suggesting ~$600/kW is between a 7-8x EV/EBITDA multiple.

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

Further details on the NY ZEC proposal are available here.

- **What else? PJM peakers.** We believe several could be on the block too 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.

Looking for synergies update upon close; this includes coal retirements

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 Coleto Coal plant in Texas; thus we believe DYN might prove among the first coal operators to shut coal in the state. We do not expect synergy updates with 2Q16, but would expect an announcement in tandem with the deal close, potentially with 3Q16 results (~October 1st).

Figure 56: DYN FCF Profile

Dynegy Free Cash Flow Analysis	2014A	2015A	2016E	2017E	2018E	2019E	2020E
Adjusted EBITDA	957	840	1,119	1,143	1,401	1,193	1,117
Less: Interest Expense	(147)	(546)	(505)	(505)	(505)	(505)	(505)
Less: Taxes	**No Cash Taxes Through At Least 2018E**					(123)	(93)
FCF Pre-Capex (Proxy for FFO)	810	294	614	638	896	565	518
Less: Capital Expenditures	(123)	(255)	(335)	(274)	(369)	(269)	(269)
Plus/Minus: Other	27	5	(20)	(3)	(3)	(3)	(3)
Free Cash Flow	**714**	**45**	**259**	**361**	**524**	**293**	**246**
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	$854	$1,226	$1,580	$1,724	$1,792
Net Debt	**$6,226**	**$6,784**	**$6,435**	**$6,063**	**$5,709**	**$5,565**	**$5,497**
Net Debt / EBITDA	6.5x	8.1x	5.7x	5.3x	4.1x	4.7x	4.9x
FFO / Gross Debt	11%	4%	8%	9%	12%	8%	7%
FCF Yield	**34.0%**	**2.1%**	**12.3%**	**17.2%**	**24.9%**	**13.9%**	**11.7%**

Source: Company Filings and UBS Estimates

Valuation: Maintaining $22 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. Our valuation reflects retirement of Coleto Creek in 2017+ as well as unit outage at Hanging Rock.

Figure 57: Maintain Dynegy Valuation: The Engie Mini-Model Uplift is Included

		EV / EBITDA Multiples					
Dynegy Inc - 2018E	**EBITDA**	**Low**	**Base**	**High**	**Low**	**Base**	**High**
Base IPP Multiple =			7.0x				
Legacy Dynegy	327	4.0x	6.0x	7.0x	$1,310	$1,965	$2,292
Illinois Power Holdings (IPH)	169	3.0x	5.0x	6.0x	$506	$844	$1,013
Duke Midwest	300	6.0x	7.0x	8.0x	$1,803	$2,103	$2,404
EquiPower (~ISO-NE Portfolio)	445	6.0x	7.0x	8.0x	$2,668	$3,113	$3,557
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	566	6.0x	7.0x	8.0x	$3,396	$3,962	$4,528
Total Unregulated EV	**1,967**	**5.3x**	**6.5x**	**7.5x**	**$10,393**	**$12,838**	**$14,788**
Net Debt (12/31/15)							
Dynegy Inc.					$6,380	$6,380	$6,380
Illinois Power Holdings (IPH)					$825	$825	$825
Engie-Related Financing					$2,000	$2,750	$3,150
Plus: NPV of West Peaking					($25)	($45)	($50)
Cash and Equivalents					($253)	($505)	($880)
Total Net Debt					**$8,928**	**$9,405**	**$9,425**
Net Debt / Adjusted EBITDA					*4.5x*	*4.8x*	*4.8x*
Removing Net Equity Drag of IPH					$319	$0	$0
Total Equity Value					**$1,784**	**$3,433**	**$5,362**
Implied FCF Yield					*20%*	*11%*	*7%*
Estimated Shares Outstanding (Mn)					158	158	158
Dynegy Valuation					**$11.00**	**$22.00**	**$34.00**
Upside/(Downside)					**-35%**	**31%**	**102%**
Price Target Gross EV/EBITDA Multiple					*5.3x*	*6.5x*	*7.5x*
Current Price Implied Gross EV/EBITDA Multiple					*5.5x*	*5.8x*	*5.8x*
Dilution Implied from Consolidating IPH					*-$2.01*	*$0.12*	*$1.19*

		EV / EBITDA Multiples					
DYN Engie Portfolio	**EBITDA**	**Low**	**Base**	**High**	**Low**	**Base**	**High**
ISO-NE	210	6.0x	7.0x	8.0x	1260	1470	1680
PJM	171	6.0x	7.0x	8.0x	1026	1197	1368
ERCOT	185	6.0x	7.0x	8.0x	1110	1295	1480
Total Unregulated EV	**566**	**6.0x**	**7.0x**	**8.0x**	**$3,396**	**$3,962**	**$4,528**
Pro-Forma Financing							
Secured Debt					(2,000)	(2,000)	(2,000)
Mandatory Convert ("Tangible Equity Units")					(400)	(400)	(400)
DYN Equity Sale to ECP					(150)	(150)	(150)
DYN Forward Capacity Sale					(200)	(200)	(200)
DYN Cash/Borrowing Contributed					(550)	(550)	(550)
Total Debt+DYN Equity					(3,300)	(3,300)	(3,300)
Total Equity Value					**$96**	**$662**	**$1,228**
DYN's Equity Value (65%)	**100%**				**$96**	**$662**	**$1,228**
Shares Outstanding					137	137	137
Dynegy Valuation					**$1.00**	**$5.00**	**$9.00**

Source: Company filings, FactSet, UBS estimates

NRG Energy Inc.

As attention grows on the GenOn negotiation process, management has stated that it will be disciplined when dealing with creditors and will seek to preserve its balance sheet while working to offset dis-synergies.

We forecast NRG Energy reporting 2Q16 adjusted EBITDA of **$668 Mn**, modestly behind Street consensus (~$683Mn). Hedges are rolling off in the Northeast, which means results are likely to be impacted in addition to the Gulf. We suspect mild weather likely drove resilient Retail. We do not expect a shift in guidance either, albeit acknowledge that mild weather could yet place a broader negative bias on FY16 results.

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 58: NRG 2Q Results Adj. EBITDA Comparison

NRG Energy Adjusted EBITDA ($Mn)	1Q15A	2Q15A	1Q16A	2Q16E	2Q +/-	UBSe FY16	NRG 2016 Guidance *	2015A
Business								
East	182	144	245	129	(15)	541		1,057
Gulf Coast	91	115	123	95	(20)	321		588
West	(8)	20	55	30	10	107		102
Business Total	265	276	423	254	(22)	969		1,738
NYLD	122	187	188	242	55	803	805	-
Corporate and Other	281	53	44	(21)	(74)	692		926
Wholesale - Total	387	463	611	496	33	1,772	1545-1670	1,738
Retail Businesses	172	213	151	253	40	653	$650-$725	653
Adjusted EBITDA	**840**	**729**	**806**	**728**	(2)	**3,116**	**3,000-3,200**	**3,316**
Street Mean EBITDA Est.				*683*			*3,089*	

Source: Company reports, ThomsonReuters, UBS estimates

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

6/9/16: Gen Off? Downgrade to Sell
5/19/16: Selling the Northern Lights
5/18/16: NYLD: Equity-less Drop
5/5/16: Sprucing Up the Portfolio
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: Lightening Up at GenOn

What are the key updates for NRG?

- **Mauricio's Three Key Sayings:** Recently anointed CEO has three key pillars of the NRG equity story on which he is focusing the story: 1) Simplification, primarily addressing GenOn; 2) Protecting the Balance Sheet, including paying down medium term maturities; and 3) Creating Value for All Stakeholders, including creditors at GenOn and elsewhere within the Capital Structure.

- **Reducing Costs All Around:** With the 2Q update the first since the latest PJM capacity auction, we expect updates on coal assets here too. We emphasize the outlook suggests an effort to reduce costs and effectively harvest assets. Cost reductions could yet help alleviate pressures at both GenOn as well as the wider entity. This could be a positive factor for ~2017 estimates with 2Q. This reduction in investment in peripheral plants is consistent with the strategy on improving FCF with a step-up in capex in 2017.

- **Pushing out remaining debt obligations:** We look for more debt reduction through the near term, largely pushing out all debt through 2020. Of the ~$5

Bn in maturities, there is just $518 Mn in 2018 left. This too is likely to be addressed in the near-term to fully execute on management's stated plan.

- **Running through the GenOn Dynamics:** NRG stated on its 1Q16 earnings call that it would negotiate with GenOn creditors in the near term and according to media reports NRG plans to hire a restructuring advisor to help in the efforts. The most significant uncertainty continues to revolve around the outlook for the non-recourse GenOn subsidiary. Raising $491Mn of proceeds from asset sales will help facilitate the negotiation but there is still $1.34Bn of obligations due in 2017/2018 that need to be addressed.

We emphasize management appears poised to pursue additional asset sales in coming periods, likely including one or two CCGTs as part of efforts to raise liquidity to address the 2017 maturity.

  - **Legacy services arrangement is a key area of attention:** We expect the dynamic between creditors and management to intensify in coming months as focus on restructuring options for the highly-leveraged but non-recourse subsidiary grows. We emphasize management appears poised to pursue further asset sales in coming periods, likely including one or two CCGTs as part of efforts to raise liquidity to address the 2017 maturity. <u>We expect creditors to push for a reduction in the size of its services payments back to the NRG Energy parent, with the current $193Mn based on pre-2013 cost structure but GenOn now owns 25-30% less capacity</u>. <u>Mgmt is quite confident it largely offset any loss of the business.</u>

We believe the intercompany support agreement could be renegotiated lower in the future following the recent asset sales and retirements.

This remains the primary overhang on the stock beyond restructuring events.

    Discussions on the equity remain focused on how large this payment would be. Management did not elaborate on any plans around this—or any other tangible strategies at GenOn. We see a reduction in the G&A payment at least proportionate with the asset sales, if not materially more. The Street expectation for the new services payment is a wide range of $50-$150Mn but is consistently materially lower. We emphasize the dynamic between the parent and GEN subsidiary could become more contentious as focus swirls around bidding practices in energy and capacity markets, as well as focus on the transfer of assets between the subsidiary and the parent (ex. leasing land to NRG for new Mandalay and Canal constructions). The claim appears to be that the GenOn acquisition was structured to effectively extract cash from the subsidiary via 'above-market' services arrangements, rather than 'at-cost'.

Further, we see other risks relating to NRG's relationship with GenOn including tax attribution (NOL benefits) and contracting/retail commitments

  - **What kind of combination would be palatable for a restructuring for NRG?** NRG continues to look at any kind of restructuring with GenOn as closely focused on maintaining reasonable credit metrics back at NRG Corp. As a consequence, the objective would be to limited recourse debt to 4.25x adjusted EBITDA. With GenOn seemingly north of 9x+ Debt/EBITDA using the valuation framework below, we expect that any exchange offer back to the parent would include a combination of debt and NRG common equity (or equivalent). Even assume the portfolio is acquired at a valuation of 6-7x EBITDA (below current trading value of bonds), this could still involve ~$600 Mn - $1Bn in total common equity ($2/sh or more not yet reflected in our valuation) assuming just 4x Debt/EBITDA is exchanged in the form of NRG debt.

How does a GenOn restructuring resolve itself?

NRG has stated that it would try to manage the GenOn situation to protect the NRG Corp balance sheet and maintain value for equity holders.

  - **Other Genon subsidiaries will eventually need addressing as well:** Further, with negligible value from the REMA and Mid-Atlantic leases regardless, we see a potential view that little in terms of cost allocation 'benefits' should be paid to GenOn Corp creditors (seeing they are still subordinated to these further layers of leverage). Bottom line, addressing

the GenOn HoldCo notes is just the start. Moreover, disynergies potentially lost from retirements and loss of assets at these levels only add to the GenOn risk and timeline in future years.

- **Secured debt capacity at GenOn:** Among the key levers remaining to address the forthcoming maturity in 2017 is untapped secured debt capacity which management has estimated at ~$700Mn at the GenOn Corp level and a further $200Mn at the GenOn Mid-Atlantic Generation (GAG) level. Given the challenging outlook we believe adding even secured debt could be an issue with a negative FCF profile. We emphasize even paying down 2017 with existing liquidity, 2018 is still likely the key challenge.

- **Is there risk between the NRG and GenOn Corp Structure?:** We note some investors of late have been focusing their efforts on this angle. While difficult to assess given the explicit structuring at the time of the GenOn acquisition to ensure a continued structural separation between the two entities (and without any formal distributions ever), there are a few clear datapoints to suggest this is the case. We note Tim Toy, a legal expert, and others have pointed to the discrepancy between the 36th indenture and the base indenture with respect to acceleration of liabilities due at *all* subsidiaries vs. *unrestricted* subsidiaries. We suspect additional focus may grow around this nuance in coming months as the ongoing restructuring conversations continue between creditors and NRG management.

Has the 36th indenture *replaced* the Base?

Management is confident on the ringfencing.

- **No New Equity:** Mgmt does not see an outcome in which NRG equity would be paid for the GenOn assets. With a goal of maintaining holding company leverage at 4.25x at the parent, this could imply debt at ~50c, relative to the ~80c market value today. Bottom line, we think mgmt is effectively saying they will not negotiate with lenders unless at a substantial discount.

- **Addressing the discount sooner than later.** Given the clear indications in strategy that no new equity issuances would be palatable, we would not be surprised to see a readily executed decision on the GenOn business in months well ahead of the contemplated 2017 maturity.

- **Does NRG *need* GenOn for retail obligations? No.** Mgmt is increasingly clear it hedge its PJM risk via both its legacy PJM footprint as well as the EME portfolio it acquired several years ago. This portfolio, while located in NI Hub appears to offer sufficient generation exposure, albeit there appears a clear basis exposure within the footprint. Bottom line, we don't perceive the generation alignment with retail as forcing mgmt to maintain the biz through any restructuring of this highly leveraged subsidiary.

- **De-emphasizing PJM footprint:** We perceive mgmt as focused on talking down expectations for the core PJM footprint, particularly into any potential filing of its GenOn business. Rather, the core of the business remains the NI Hub market with the EME portfolio (and uplift from recent nuclear retirements), the retail business (and meaningful FCF contributions), as well as dividends from its NYLD business and other 'to-be-dropped' renewable assets.

- **NYLD: Restarting the ROFO Pipeline & More:** We think the most likely outcome for NYLD is largely status quo in relation to NRG; rather than scaling back we anticipate NRG is poised to ramp back *up* its efforts with respect to NYLD. In particular, we see a delineation of a wider ROFO pipeline as well as potential independent ROFO arrangements as likely next steps with Chris Sotos now as the independent CEO of the organization. We reiterate NYLD as our preferred YieldCo idea.

  We reiterate our overall preference for this sector amidst a declining interest rate environment. We emphasize project debt terms continue to decline in costs and spreads for the sector, with recent deals swapped into ~4% term paper. We look towards levered YieldCos to discuss this improvement in their financing prospects.

- **Just how much CAFD could be generated from CVSR?** We emphasize that the available CAFD could be as low as ~single digit millions by the time debt amortization and interest expense is accounted for depending on the magnitude of debt and amortization profile assuming entirely debt financed (CVSR would also transfer $398Mn of project level debt).

- **Aurora Asset Sale Latest; Don't Expect Others Like This:** Below we show the mini-model for the Aurora asset with no real energy margin and all of the economic value derived via capacity payments. Even based on our assumption that capacity prices will increase to $225/MW-Day in the upcoming 2019/2020 Capacity Auction there is no material impact on the plant compared with the $215/MW-Day price in the last auction; however, if capacity prices decline towards the RTO level ($160/MW-Day or lower) we believe this would significantly reduce the free cash flow profile of the asset. Further, given the limited run times capacity performance (CP) compliance risk is likely not trivial.

  Using a 9.6% discount rate we estimate a $260-$310Mn NPV depending on the assumed useful asset life and keeping ComEd pricing constant into the 2020s.

We see NYLD as particularly well positioned into 2Q for ROFO updates and more

Figure 59: CVSR Drop Analysis

CVSR Drop (UBSe)	EBITDA	CAFD
Implied CVSR Guidance	55	25
Incremental Financing		(11)
Debt Assumed ($Mn)	398	398
Equity to NRG ($Mn)	150	200
Total EV	548	598
EV / EBITDA	**10.0x**	**10.9x**
Gross CAFD Yield (%)	**17%**	**13%**
Net CAFD Yield (%)	**12%**	**9%**

2Q16E Liquidity Walk ($Mn)	
Unrestricted Cash 1Q16	76
Revolver Availability 1Q16	119
Plus: 2Q16E CAFD	66
Less: 2Q16E Dividend	(42)
Pre-CVSR Liquidity	219
Less: CVSR Midpoint	(175)
Plus: Estimated Project Debt	88
2Q16E Ending Liquidity	**132**

Source: Company Filings and UBS Estimates

How to make sense of the deal price?

The deal would appear consistent with similar transactions involving peaking facilities in the adjacent MISO market on continued and sustained capacity prices in this region. The purchase price for Aurora seemingly embeds a view on eventual nuclear plant retirements.

Figure 60: Aurora Generating Station Mini-Model

Aurora Peaker	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity	878	878	878	878	878	878	878	878	878	878
Capacity Factor, UBSe	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
NI-Hub Peak ($/MWh)	39	38	34	35	35	33	34	34	35	35
Bias for Super-Peak ~50%	20	19	17	18	18	17	17	17	17	17
Heat Rate	12,370	12,475	12,475	12,475	12,475	12,475	12,475	12,475	12,475	12,475
Variable Cost ($/MWh)	(57)	(35)	(35)	(40)	(40)	(42)	(42)	(42)	(42)	(42)
Energy Margin ($MWh)	2	23	16	13	12	8	9	9	10	10
Generation (TWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Energy Margin ($Mn)	0	1	1	0	0	0	0	0	0	0
PJM ComEd Capacity Payment ($/MW-day	182	136	135	144	189	221	225	225	225	225
Capacity Revenue ($Mn)	52	39	39	42	54	64	65	65	65	65
O&M ($/kW-yr), UBSe	10	10	10	10	10	10	10	10	10	10
O&M ($Mn)	9	9	9	9	8.78	9	9	9	9	9
EBITDAR	**44**	**31**	**31**	**33**	**46**	**55**	**56**	**56**	**57**	**57**
Less: Maintenance Capex ($5kW-yr)	4	4	4	4	4	4	4	4	4	4
Less: Major Maintenance	-	-	-	-	-	-	-	-	-	-
Free Cash Flow	**39**	**27**	**26**	**29**	**42**	**51**	**52**	**52**	**52**	**52**
EV/EBITDA Multiple	**9.3x**	**13.5x**	**13.9x**	**12.6x**	**8.8x**	**7.2x**	**7.0x**	**7.0x**	**7.0x**	**7.0x**
NPV 15Yr	**306**		**NPV / 2018 EBITDA**		**9.2x**			**NPV $/kW**		**348**
NPV 10Yr	**264**		**NPV / 2018 EBITDA**		**7.9x**			**NPV $/kW**		**300**

Source: Company Filings, Platts, PJM, SNL Energy, and UBS Estimates

How does this compare versus the other deals?

The Aurora divestiture will generate significantly more value than the 4Q15 transactions and represents a substantial premium to the other Illinois transaction (Shelby) recently executed.

<u>The real remaining asset with a potentially big multiple sale:</u> We emphasize that we do *not* expect any further deals quite like this one. The most important remaining asset sale within the portfolio is clearly the 800MW Choctaw CCGT, however there have been developments to indicate a sale to its local utility, Entergy.

Figure 61: Recent GenOn Divestitures

Divested Asset	MW	Fuel	Region	Price ($Mn)	$/kW
Seward	525	Coal	Pennsylvania	$75	$143
Shelby County	352	Gas	Illinois	$46	$131
Aurora	878	Gas	Illinois	$365	$416
Total	**1,755**			**$486**	**$277**

Source: Company Filings

Latest MtM Outlook

We include our latest look at forward EBITDA estimates. We do not expect management to revise its consolidated EBITDA guidance but do expect further updates on long-term cost reductions.

Figure 62: Updated NRG Energy Adjusted EBITDA Estimates

NRG Energy EBITDA ($Mn)	2015A	2016E	2017E	2018E	2019E	2020E
NYMEX Assumption	*2.51*	*2.51*	*3.16*	*3.04*	*3.17*	*3.17*
Texas	470	187	82	64	84	13
South Central	118	134	117	139	140	116
Northeast	1,033	531	380	436	405	365
West	102	107	114	96	98	98
NYLD Eligible	171	225	233	311	311	348
Renew						
NYLD	720	803	801	800	799	799
Guidance	*705*	*805*				
B2B						
Home						
Retail Businesses	739	653	651	683	682	715
Home Guidance	*700-750*	*650-725*				
Corporate, Other, and Unallocated Synergies	(37)	467	537	537	537	537
NRG Adj. EBITDA (UBSe)	3,316	3,105	2,915	3,065	3,056	2,991
Prior EBITDA Est. (UBSe)	3,397	3,113	2,944	3,068	3,065	
Consensus EBITDA Est. (5/31/16)	3,235	3,103	2,822	3,012	2,913	
Guidance (1Q16)	$3,250-$3,350	$3,000-$3,200				

Source: Company Filings, ThomsonReuters, and UBS Estimates

Valuation: Dropping PT to $15 from $16

We include our latest valuation below; our changes below reflecting:

1. Latest shifts in commodity MtM (+$1/sh), including better rail terms to Texas and the Southeast on the back of reduced pricing discussion regionally.

2. Impact from GenOn dis-synergies: In an effort to fully capture the potential negative, we are assuming the loss of GenOn and the immediate loss of ~$50 Mn in dis-synergies. Mgmt's latest guidance suggests the lost allocations can be 'substantially' offset.
   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 63: NRG Energy Valuation: Slightly Tweaked Lower

NRG Energy Valuation	2018 EBITDAR	EV/EBITDA Multiple				Enterprise Value ($Mn)		
NRG Energy (Classic) and GenOn		Low	Prem/ Discount	Base	High	Low	Base	High
Base IPP Multiple =				7.0x				
Texas	64	6.0x	0.0x	7.0x	8.0x	382	446	509
Northeast	178	6.0x	0.0x	7.0x	8.0x	1,067	1,245	1,422
GenOn Operating Leases	80	5.0x	-1.0x	6.0x	7.0x	400	480	560
South Central	139	6.0x	0.0x	7.0x	8.0x	834	973	1,113
West (All-Inclusive)	96	4.0x	-2.0x	5.0x	6.0x	385	481	577
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
Edison Mission								
EME - MidWest Generation	228	6.0x	0.0x	7.0x	8.0x	1,369	1,597	1,825
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
Other, Corporate, and Unallocated Synergies	523	6.0x	0.0x	7.0x	8.0x	3,135	3,658	4,180
Total / Implied	2,371	*5.9x*	*-0.1x*	*6.9x*	*7.9x*	14,082	16,453	18,824
Net Debt and Other: 12/31/15								
NRG Recourse Debt						(8,586)	(8,586)	(8,879)
GenOn Non-Recourse Debt						(2,584)	(2,584)	(2,003)
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)
Pending Asset Sales						426	426	426
Cash						1,358	1,358	1,358
Add: NRG Yield Home Solar ~93MWs (YE15) @ $0.15 CAFD/Watt @ 10% discount rate						140	140	140
NPV of Equity using Hedged EBITDA Methodology						1,535	3,906	6,565
Open Analysis								
Power Hedges	(185)	5.9x		6.9x	7.9x	(1,100)	(1,285)	(1,470)
Total						(1,100)	(1,285)	(1,470)
add NPV of Power Hedges							349	
NPV of Equity using Open EBITDA Methodology						784	2,970	5,444
GenOn Add Back of Neg Equity Value						$3.20	$2.95	-
Add: GenOn Loss from Synergies (~$50 Mn @ Base Multiple)						-$0.95	-$1.11	-
NYLD Class A & C Average Share Price						13.46	14.96	16.46
NYLD Equity Value						1,150	1,278	1,405
$/share for NRG Energy (85Mn Shares Owned (B & D)]						3.65	4.06	4.46
Estimated 2018 Shares Outstanding						315	315	315
Equity value per share (using Avg of Open/Hedged)						$8.00	$15.00	$22.00

Source: Company filings, UBS estimates

NRG Consolidated FCF (both incl/excl NYLD and GenOn)

Figure 64: NRG FCF Projections

EBITDA to Cash Flow Analysis	2015	2016	2017	2018	2019	2020
NRG:						
Consolidated EBITDA	3,340	3,105	2,915	3,065	3,056	2,991
Interest Expense	(1,158)	(1,400)	(1,412)	(1,363)	(1,220)	(1,149)
Income Tax	-	-	-	-	-	-
Collateral / Working Capital	(685)	(26)	25	165	2	9
Other / Deferred Taxes	(15)	477	353	274	295	331
Less: Home Solar	(173)	(100)				
CFO	1,309	2,057	1,882	2,140	2,133	2,183
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)
FCF Pre-Growth Capex	1,127	1,323	1,493	1,741	1,729	1,774
Guidance	*1,100-1,300*	*1,000-1,200*				
Amortization Schedule - Non-NYLD						
Agua 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
Debt Amortization	121	124	128	132	135	93
Adjusting for NRG Yield						
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	71	81	91	102	107	107
Total NYLD Adjustment	(415)	(488)	(476)	(464)	(459)	(459)
Adjusting for GenOn Energy	(255)	(359)	(252)	(148)	(241)	(233)
Total NRG Free Cash Flow	833	959	1,145	1,409	1,406	1,408
		750-950				
Market Cap	4,891	4,891	4,891	4,891	4,891	4,891
Less NYLD Stake	1,203	1,203	1,203	1,203	1,203	1,203
Market Cap (ex-NYLD)	3,687	3,687	3,687	3,687	3,687	3,687
Implied FCF Yield (with NYLD)	17%	20%	23%	29%	29%	29%
Implied FCF Yield (without NYLD)	23%	26%	31%	38%	38%	38%
GenOn EBITDA	509	314	183	225	173	138
Interest Expense	(202)	(239)	(239)	(239)	(239)	(239)
Maintenance Capex	139	152	94	82	82	82
Environmental Capex	36	62	-	-	-	-
Total Capex	254	334	100	86	82	82
Free Cash Flow (Pre-Leveraged Lease	53	(259)	(156)	(99)	(148)	(183)
Net Leveraged Lease Impact (Debt A	(86)	(100)	(96)	(49)	(93)	(50)
Free Cash Flow (Pre-Leveraged Lease	(255)	(359)	(252)	(148)	(241)	(233)
Uses						
Organic Growth Capital	900	500	500	-	-	-
Total Capex	1583	1,225	880	390	395	400
Assumed Share Repurchases	(1)	-	-	-	-	-
Projected Common Dividend	201	74	38	38	38	38
Remaining for Debt Paydown, etc.	(656)	24	575	1,313	1,296	1,336

Source: Company reports, UBS estimates

GenOn Outlook: A Tad Brighter

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.

Our latest update also removes the PJM East DCF. Following confirmation from a variety of parties the PJM East portfolio will likely continue to operate beyond the 2020 implementation of Phase 2 of the Maryland Healthy Air Act regulations *without* meaningful capital we are returning to putting a multiple on the business rather than simply a 5-year DCF. We emphasize the lower 6x multiple on near-year EBITDA does not driven a materially better outlook.

We're comfortable Dickerson, Morgantown, and Chalk Point will survive MD HAA under Gov Hogan in Maryland

Figure 65: Updated GenOn Subsidiary Valuation

GenOn Energy	2018 EBITDA	EV/EBITDA Multiple				Enterprise Value ($Mn)		
GenOn Mini-Model SOP Valuation		Low	Discount	Base	High	Low	Base	High
Eastern PJM	32	5.0x	-1.0x	6.0x	7.0x	161	193	225
Western PJM/MISO	86	5.0x	-1.0x	6.0x	7.0x	431	518	604
California	27	4.0x	-2.0x	5.0x	6.0x	106	133	159
Other (New England, NY etc.)	88	6.0x	0.0x	7.0x	8.0x	530	619	707
Energy Marketing/Gas Contracts	(8)	5.0x	-1.0x	6.0x	7.0x	(40)	(48)	(56)
GenOn EBITDA	*225*	*5.3x*		*6.3x*	*7.3x*	*1,189*	*1,414*	*1,639*
GenOn Operating Leases	80	5.0x	0.0x	6.0x	7.0x	400	480	560
GenOn EBITDAR	305	*5.2x*		*6.2x*	*7.2x*	1,589	1,894	2,199
Net Debt and Other: 12/31/15								
GenOn Senior Notes						(1,830)	(1,830)	(1,418)
GenOn Americas and Other						(754)	(754)	(584)
PV of GenOn Mid-Atlantic Operating Lease						(672)	(672)	(672)
PV of REMA Operating Lease						(376)	(376)	(376)
Pending Asset Sales						370	370	370
Cash (12/31/15)						665	665	665
Net Equity Value to NRG Corp						(1,008)	(703)	184
Net Equity Value to NRG Corp (per Share)						-$3.20	-$2.23	$0.58
Implied 'Fully Loaded' Net Debt & Leases/EBITDA							*8.5x*	

Source: Company filings, Platts, UBS estimates

Calpine Corporation

2Q expectations should be ahead; it's a quiet story for now

Decent quarter ahead

We forecast Calpine reporting 2Q16 adjusted EBITDA of **$443Mn**, better than the Street at $401 Mn. 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 (2Q is a big run-off quarter likely pressuring volumes by at least 2-3TWhs). See the charts below on improving conditions. We suspect conditions were aided in 2Q to continued substantial switching albeit off YoY. In its latest quarter owned by Calpine, we estimate that Granite Ridge contributed ~$10Mn at best given continued mild Northeast conditions.

Figure 66: CPN 2Q16 Adj EBITDA Walk

Calpine Corp 2Q16 EBITDA Walk		
2Q15A Adjusted EBITDA	**$457**	**Notes**
Capacity Price Changes		
RA Payments (California)	-	
Non-California (PJM, etc.)	(5)	PJM Rolloff YoY, improvement in June
Energy Margin		
Geysers Outage	-	Geyser Deductibles Incurred, so insurance will roughly offset
Hedge Position	(5)	Open hedges declining substantially (except for PJM West)
Garrison CC	5	Full Quarter Contribution
Granite Ridge	10	Acquisition closed 2/5/2016
Total Uplift	**10**	
Volumetric Improvement	(30)	Well Diversified Provided a Normal Quarter/ Hydro Pressures in West
Net Change	**(14)**	
2Q16A Adjusted EBITDA	**443**	
2Q16A Adjusted EBITDA Consensus	***$401***	
2016 UBSe EBITDA	**1,915**	
2016 Consensus	**1,874**	
2016 Guidance	**$1,800-$1,950**	

Source: Company reports, ThomsonReuters, UBS estimates

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

5/2/16: Successfully Navigating A Warm Winter
2/16/2016: Preparing for a Gradual Debt Paydown
2/12/2016: Pausing on Buybacks
11/2/2015: Reaching the Trough

What does 2017 Guidance Look Like?

We include our initial cut of a YoY walk on the guidance factors driving 2017 to be a positive YoY guide vs. 2016. We note a partial year of the York II CCGT in PJM drives the bulk of the delta. Further, we note the Granite Ridge is a partial contributor as well. We see a range of $1.95-2.15 Bn as likely, with a $200 Mn band. We suspect Street consensus EBITDA of just north of $2 Bn is appropriate in the context of the new assets, higher capacity payments, and further CCGT expansions. We suspect further expansion of retail efforts could yet drive upside.

With expectations on guidance typically becoming a defining 3Q event for shares, we include our walk in an effort to address this concern.

Figure 67: 2017 vs. 2016 YoY Walk on FY Adj EBITDA Guidance

2016 EBITDA Estimate	**$1,913**	
Revenue Type Walk	***Items***	*Notes*
Total (PJM, etc)	**31**	Step-up in PJM Capacity Rev's
York II/Expansion CCGT (Summer '17)	**52**	June, 2017 In-Service (Partial Year)
York Toll Expansion		*Close to ~Market Prices*
Granite Ridge (Partial Year)	**6**	February, 2016 Acquisition
Hedges	**32**	Delta -$3/MWh on Open Volumes
2017 EBITDA Estimate	**2,034**	
UBSs Expected Guidance Range	**1950-2150**	
UBSe Point Estimate	**2,036**	
Consensus	**2029**	

Source: Company reports, ThomsonReuters, UBS estimates

What about the hedges?

Calculating the precise YoY shift in hedge value is among the biggest deltas in our assumptions above. We see appropriate estimation of the rolloff of this hedge profile as critical in deriving the trend; we note while opaque in its precise calculation, it would appear as if hedges skew slightly positive in energy margins.

Figure 68: Hedge Value and Open Market Comparison

Hedging	2016		2017		2018	
	$/MWh	Percent	$/MWh	Percent	$/MWh	Percent
1Q16	$18	86%	$24	48%	$32	28%
4Q15	$19	80%	$27	38%	$34	25%
3Q15	$16	63%	$27	27%	$32	19%

Source: Company reports and UBS estimates

What are the key updates for CPN?

- **South Point: Sold For A 'Not So Hot' Price:** We flag the South Point price is nominally low, but has many adjusting factors which make it a more relatively equivalent price to other asset sales. We note we had already assumed a low valuation given the contract is among the few uncontracted plants in a regulated market.

Prices appear quite low, but are principally due to high operating costs and poor location.

Adjusting for incremental factors lands more comparable prices

Figure 69: Estimated Breakdown of Economics

Southpoint Sale in Nevada ($ Mn)		$/kW Equiv on 520 MWs
75.6	**Purchase Price (received by CPN)**	***145***
3.6	Integration Costs	*7*
20.8	Required Investment	*40*
100	Subtotal	*192*
112	NPV of Transmission	*215*
212	**Grand Total for NV Energy**	***408***

Source: Company disclosures and UBS estimates

The plant is located not just in the regulated Southwest market, but also is not near a load pocket and sells into the expensive WAPA transmission system (akin to Sutter selling into Smud, outside of CAISO in California). The transmission described above is a ~$10 Mn/yr payment for 25-years to ensure the plant is deliverable. Further, it suffers from higher property taxes, natural gas taxes and higher operating costs due to Native American tribal lease. Lastly, there is a legacy steam turbine issue that has not been fixed (~hence the $21 Mn in costs above) to ensure the plant is back to its full capacity.

While likely the best deal possible for shareholders given the disadvantages, we suspect Western power plant datapoints will remain distresses as buyers are well aware of the issues. We emphasize regional price points could yet head lower as renewables continue to cloud the fundamental need for these assets coupled with increasing uncertainty as merchant plants generate negative FCF stand-alone.

RFPs in Arizona: Don't Expect Much Either

For other plants seeking to participate in the ongoing PNW All-Source RFP we don't see a silver lining here either as generators are keen to participate in this 400-600 MW procurement (for 2020). Given the summer-only needs we suspect pricing will be quite low, designed to entice peakers to participate. We suspect PNW may well move to acquire into ratebase any plant ultimately participating in this process, albeit don't expect any details until at least December when bids are due. Lastly, given the willingness to evaluate storage + solar solutions, the RFP would well have further pressure on prices as gas assets must ensure they are competitive vs. solar resources, which benefit from the ITC.

Looking the Other Southwest assets: Prospects tied to RFPs still

Interest in the region has grown of late following a recent debt deal for the Starwest portfolio. We emphasize the Arlington Valley asset for this portfolio sits near Harquahala and other CCGTs in the 'power' corridor previously to California. We suspect prospects for getting contracted remain principally tied to Salt River Project or APS – and look for developments. In contrast, the Griffith plant near the NV border appears more tied to prospects with NV Energy (as well as nascent efforts for restructuring for larger commercial entities appears a further angle as well, albeit for smaller slices).

- **Calpine: More Divestment? Looking at Track record:** Calpine's largest non-core sale was its 3.5GW divestiture of its Southeast Portfolio for $1.57Bn ($1.53Bn cash proceeds) in April 2014. Below we show other non-core asset sales executed by management since 2010 and although different markets are not ideal for comparisons, the clear trend is that pricing has declined in these regulated markets.

  We suspect among the next asset focuses will be Hermiston in Oregon given the upcoming RFP for new generation in the state. The question is whether an additional brownfield expansion for POR will be more economic than buying the uncontracted plant in the state. We suspect both historic terms on offer to contract the plant or sell the plant have proved unpalatable.

Figure 70: Calpine Non-Core Asset Sales: South Point is UBSe

Assets	Date	Region	Capacity	Sale Price	$/kW Value
South Point Energy Center	Apr-16	AZ	520	76	$145.4
Osprey Energy Center	Jan-15	FL	600	166	$276.7
Oneta, Decatur, etc.	Apr-14	South East	3,498	1,570	$448.8
Broad River	Nov-12	SC	847	427	$504.1
Riverside Energy Center	May-12	WI	600	402	$670.0
Rocky Mountain & Blue Spruce	Apr-10	CO	931	739	$793.8

South Point sets a new low bar

Source: SNL Energy, Company Filings, and UBS Estimates

Issues to Address on the Call

- **What about the West Portfolio Value?:** The underlying question amidst the latest sale in NV as well as any likely low print in the state for DYN's own Moss 1&2 print (we acknowledge this is *below* that of CPN's assets given unattractive location) is what is Calpine's Western portfolio worth?

- **Metcalf Energy Center is probably next asset to focus on?** We emphasize the Metcalf Energy Center (South of the Bay Area) is the latest completely unhedged CCGT for Calpine in California. We tweak down our expectations here from $250/kW to $200/kW. We note this is distinctly different from peers as the unit was in recent years contracted under a lucrative local *resource adequacy (eg- constrained*) capacity payment. We see upside to the plant even if only partially contracted. The plant is located near the pivotal Metcalf transmission station at which there appears a power bottleneck per CAISO.

- **Further retail acquisitions: with a Northeast focus?** Following the success of Champion, we would not be surprised to see management further expanding into the Northeast to complement its assets. Calpine recently expanded its Champion retail effort into neighboring Maine and Connecticut and stated it would like to further grow the retail footprint. This remains part of a wider industry effort we have seen of late. Among companies with known divestments ongoing is ConEd Solutions. Both PSEG and Calpine have indicated an interest in scaling their business.

Revisiting Capital Allocation

Management highlighted <u>the callable 2023 first lien secured notes with a book yield of 7.88% (current yield 7.4%) as offering an opportunity</u> since it is the most expensive piece of long-term debt in the structure. $120Mn of the debt can be called in December at 103 with the balance able to be called in January 2017. Another area discussed was refinancing the 2019 and 2020 first lien term loans.

Recovery in Calpine's bond pricing reduces the return profile of repurchasing debt below par but also reduces the pro-forma interest expense on new issuances.

Calpine's debt has appreciated lately and is now trading above par. For example the 2025 senior notes were trading in the 85-90 range in February and have increased sharply to above par.

Figure 71: Updated Calpine Long-Term Debt

As of 3/31/16 (Except Current Yield)	Maturity (yr)	Book Yield	Current Yield	2015	2016	2017	2018	2019	2020+	Current Price
Calpine Corp.										
2023 Senior Notes		5.38%	5.32%						1,235	101
2024 Senior Notes		5.50%	5.45%						642	101
2025 Senior Notes		5.75%	5.72%						1,531	101
First Lien Term Loan		4.30%	5.86%				-			
2019 First Lien Term Loan		4.40%	5.86%					794		
2020 First Lien Term Loan		4.30%	5.86%						377	
2022 First Lien Term Loan		3.75%	5.86%		16	16	16	16	1,505	
2023 First Lien Term Loan		4.00%	5.86%		6	6	6	6	510	
2022 First Lien Secured Notes		6.00%	5.69%						738	105
2023 First Lien Secured Notes		7.88%	7.39%						568	107
2024 First Lien Secured Notes		5.88%	5.56%						484	106
Total Calpine Corp.		**8,469**		**-**	**21**	**21**	**21**	**815**	**7,590**	
Total Maturities		**8,469**		**-**	**21**	**21**	**21**	**815**	**7,590**	
Book Interest Expense (Consolidated)		$438		Book Interest Expense (Ex-GenCo				$438		
MtM Interest Expense (Consolidated)		$491		MtM Interest Expense (Ex-GenCo)				$491		
Delta (%)		-11%		Delta (%)				-11%		
2018E EBITDA (UBSe)		$2,262		2018E EBITDA (UBSe)				$2,262		
Delta (%)		-2%		Delta (%)				-2%		
2018E FCF (UBSe)		$1,115		2018E FCF (UBSe)				$1,115		
Delta (%)		-5%		Delta (%)				-5%		

Source: Company Filings, FactSet, and UBS Estimates. * Current Yield as of April 29, 2016

Building liquidity once more

Following the Granite Ridge and Champion acquisitions management stated a priority is "rebuilding liquidity". CPN is targeting 4.5x net debt / adjusted EBITDA and net debt as of 3/31/16 increased to $11.57Bn from $10.93Bn at YE15 as CPN purchased Granite Ridge for $527Mn.

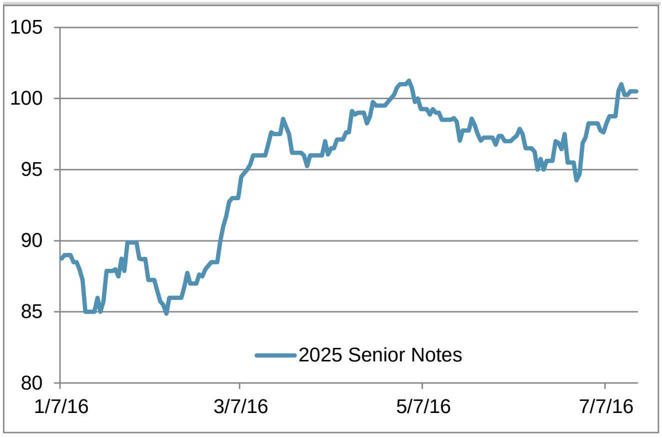
As expected there were no repurchases executed in the quarter and ~$70Mn debt amortization was consistent with 1Q15. We would not expect any (or at least not meaningful) buybacks in the 2Q period (or even through the conference call). Rather, the key question on capital allocation will remain plans in 2H as cash builds once more from recent acquisitions.

Figure 72: Calpine Capital Allocation Analysis

Calpine Capital Allocation Analysis	2016E
CPN Definiteion of Capital for Allocation	
12/31/15 Unrestricted Cash	906
Plus: 2016E FCF Generated (Midpoint)	783
Plus 2017E Proceeds from Osprey Sale	166
Plus 2017E Proceeds from South Point Sale	76
Less: Minimum Cash balance	(100)
Total Capital Available for Allocation	**1,830**
Less: Growth Capex	
Granite Ridge Purchase	(527)
York 2 and Others	(285)
Total Growth Capex	**(812)**
Less: Debt Reduction	
Required Mandatory Debt Amortization	(210)
Committed Debt Paydown	(225)
Total Debt Reduction	**(435)**
Net Capital Available Remaining	**583**
Implied Year-End Cash Balance	(1,247)
Management Liquidity Target	$1,000
Revolver Capacity	$1,542

Source: Company Filings and UBS Estimates

Figure 73: Calpine 2025 Senior Note Pricing



Source: FactSet

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. We emphasize 2017 expectations will become the key focus for shares *after* 2Q results as mgmt has had several years of more challenging EBITDA guidance vs. Consensus. We emphasize our estimates reflect the recent rally in forward sparks as well as reduced capacity factor assumptions for the Western portfolio amidst a ramp in capacity factor (%).

Figure 74: CPN estimates

Calpine Adj. EBITDA UBSe	2015	2016	2017	2018	2019	2020
West	745	610	600	606	522	516
Texas	411	438	532	594	558	530
Southeast	-	50	47	46	46	45
North	742	629	654	792	698	656
Other	30	33	35	35	36	37
Corporate Allocation	48	153	167	170	172	175
Total EBITDA	**1,976**	**1,913**	**2,036**	**2,244**	**2,033**	**1,958**
Guidance	**1965-2000**	**1800-1950**				
Street Consensus	1,991	1,918	2,059			
UBS Previous	*1,976*	*1,915*	*2,163*	*2,262*	*2,033*	*1,955*
EBITDA Change %	0.0%	0.1%	6.3%	0.8%	0.0%	-0.2%
EBITDA Change $	$0	-$1	-$128	-$18	$0	$3

Source: Company reports, ThomsonReuters, 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. We reflect both the actual sale price of South Point and updated EBITDA estimates.

Figure 75: Calpine SOP Valuation: Sticking with our $17 PT on refresh

All figures in US $ million except per share data	2018E EBITDAR	EV/EBITDA Multiple			Enterprise Value		
		Low	Base	High	Low	Base	High
West	606	5.0x	6.0x	7.0x	$3,032	$3,639	$4,245
Texas	594	6.0x	7.0x	8.0x	3,565	4,159	4,753
Southeast (Remaining)	46	6.0x	7.0x	8.0x	278	324	370
North	792	6.0x	7.0x	8.0x	4,750	5,542	6,334
Other	35	6.0x	7.0x	8.0x	212	247	282
Hedge Impact (Adj. for Steam,etc.)	(181)	6.0x	7.0x	8.0x	(1,085)	(1,265)	(1,446)
Champion Energy	63	4.0x	5.0x	6.0x	250	313	375
Adj. for Commodity Margin to EBITDA	170	6.0x	7.0x	8.0x	1,018	1,188	1,358
Total / Implied	*2,125*	*5.7x*	*6.7x*	*7.7x*	*$12,021*	*$14,146*	*$16,272*
Subtract: Net Debt						(11,309)	
Subtract: Operating Leases						(190)	
Add: NPV of NOLs						1,171	
Add: Hedge Value						517	
Add in Further Plant-Level Value	MWs	$/kW			Low	Base	High
Remaining Southeast Portfolio:		Low	Base	High			
Auburndale Peaking Energy Center (FL)	117	$100	$200	$300	$12	$23	$35
Osprey Energy Center (FL) - 4Q16 Close	599		$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
Total / Implied	1,738				*$331*	*$445*	*$559*
Subtracting out EV/EBITDA-based Value					(278)	(324)	(370)
True 'Merchant' West Portfolio:							
Metcalf (CA) - Local RA Eligible	605	$100	$200	$300	61	121	182
Hermiston (OR) - RFP Opportunity?	635	$150	$250	$350	95	159	222
South Point (AZ) - 4Q16 Close	520		$145		76	76	76
Total	1,760				*$231*	*$355*	*$479*
Subtracting out EV/EBITDA-based Value	36				(182)	(218)	(254)
NPV of Equity					$2,313	$4,593	$6,874
Projected Number of Shares Outstanding (2018E)					276	276	276
Equity value per share					$8.00	$17.00	$25.00

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 76: Our latest FCF projections

Calpine FCF Analysis (UBSe)	2014	2015E	2016E	2017E	2018E	2019E
UBS FCF Est. ($Mn)	**830**	**671**	**744**	**861**	**1,050**	**823**
		~$250 Mn uplift ex-Hedges from 2016-2018				
Management FCF Guidance ($Mn	**800-850**	**825-860**	**710-860**			
FCF per Share (using Avg)	**2.03**	**1.73**	**2.09**	**2.62**	**3.58**	**3.19**
Management FCF/Share Guidance	**$1.85 - $2.10**	**$2.25-2.35**	**$2.00-2.40**			
FCF *Growth* (YoY)	32%	-15%	21%	25%	37%	-11%
CAGR off 2011 of $1.01 FCF/shr	26.1%	14.5%	15.7%	17.2%	19.8%	15.5%
FCF Yield	**18.8%**	**15.2%**	**16.9%**	**19.5%**	**23.8%**	**18.7%**
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			
Growth Capex	**(136)**	**(355)**	**(285)**	**(265)**	**0**	**0**
Growth & Acquisition Financing		(240)	*(500)*	*Granite Ridge*		
Projected Debt Amort/Sweeps	(320)	(460)	(435)	(200)	(200)	(210)
Remaining FCF	***374***	***(161)***	***(476)***	***396***	***850***	***613***
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
Δ in Cash Balance	***(224)***	***189***	***(0)***	***-***	***0***	***-***
Deployable for Growth/Share Rep	**2,171**	**(350)**	**(476)**	**396**	**850**	**613**
Share Repurchase Placeholder	**(1,100)**	**(529)**	**(250)**	**(500)**	**(500)**	**(500)**
Projected Shares YE O/S	409	365	347	311	276	240

Source: Company reports, UBS estimates

AES Corp

We look for management to report **$0.15** adjusted EPS, a meaningful decline YoY as Outages, reversal of a one-time benefit at Eletropauloa, commodity and F/X headwinds offset much gains from growth projects. 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; further, don't look for a revision predicated on the recent rejection at the Ohio supreme court either (worth ~$0.05 for 2H impact in 2016).** In this sense, we see 2Q as remaining relatively lower key. We emphasize revisions appear for once generally positive

1Q results will maintain headwinds seen with lower guidance

Figure 77: 2Q16E YoY EPS

AES Earnings Walk	EPS
2Q15A Adjusted EPS	**$0.25**
Hydrology	0.00
Planned Outages - Argentina, etc	(0.05)
Reversal of Eletropaulo - Booked contingency on cable	(0.03)
F/X & Commodities MtM	(0.04)
Capital Allocation - Debt Paydow n	0.01
Capital Allocation - Equity Buyback	0.02
Asset Sales - Jordan CCGT, etc	0.01
Tax Rate - Was 50% in 1Q16	(0.01)
2Q16E Adjusted EPS UBSe	**$0.15**
2Q16E Consensus	***$0.17***
2016E UBSe	***1.05***
2016E Consensus	***0.99***
2016 Guidance	***0.95-1.05***

Source: Company data, Thomson Reuters, UBS estimates

What are the Key Issues for the Call?

- **Brazil**: **Both pending and further divestment.** Further divestment following media headlines of a potential sale and subsequent rebuttal. Additionally, growing confidence on macro condition in the country appears to be driving the equity of late.
- **Ohio:** How can DPL follow the FirstEnergy tune to get a similar deal in their pending ESP. Further, strategy on how to deal with the Supreme Court rejection of the existing construct is key as well.

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

6/24/2016: Getting Dinged In Dayton
6/16/2016: Saying Sul-long Brazil!
5/31/2016: What to Make of the Recovery?
2/29/2016: Doing the Debt Walk
2/24/2016: Feeling the Full Force of Forex
12/22/2015: Another Embattled IPP
11/6/15: Feeling the Global Squeeze
9/8/15: Positioning for a Turnaround

Finding a Less Turbulent Path (July 14th)

Brazil: Exiting the Volatility with strategic purpose as reducing F/X correlation

We held our latest NDR with AES mgmt this week in Europe. The most important focus remains a de-emphasis of Brazilian utilities, largely affirming a divestment strategy remains a key priority. With Brazil being the key EM country tied to shares, we believe a sale of the bulk of its consolidated exposure should meaningfully de-risk shares at least from a volatility perspective.

Growth areas are focused on two key areas – Gas and Batteries

In an effort to diversify away from coal (for which it receives increasing relative scrutiny), mgmt appears to have at least two over-arching growth strategies: the first is around an LNG driven gas strategy in Central and North America as well as a focus on battery deployments of all flavors. The final driver of growth remains the tailwind of macro factors such as F/X and commodities.

Asset sales – focused on reducing complexity and risk to boost multiple

Divestments remain focused on reducing risk in Europe and Asia, while also reducing balance complexity as few investors adequately understand the complexity of their various subsidiaries, including those that are consolidated (Eletropaulo) and those that have negligible equity value (DPL). The underlying strategic focus remains on reducing risk and growing the dividend to more align with traditional utilities. Further, a focus on peers remains a complementary effort, as efforts remain underway to tie its story more closely to the large diversified European utilities rather than heavily regulated US peers.

What do we think of shares?

We see further outperformance as tied principally to multiple expansion in LatAm as well as estimate revisions arising out of F/X improvement in Brazil. We see 2Q results as having a limited net macro impact on results despite the Latam backdrop. Despite a positive macro backdrop, we don't see a clear path towards further multiple improvement notwithstanding improvement across the wider Latam backdrop. Our price target is based on a sum-of-the-parts analysis.

What are our estimates?

Our estimates are largely unchanged vs. prior. We continue to assume our estimates the higher end of the 12-16% growth range through 2018. We emphasize a key question is the degree of slowing into 2019 YoY – with this the predominant focus with 4Q16 results as investors ask for more of a 'normalized' view of growth adjusted for the 'catchup' in the macro that drives at least 5% of the near-year bump (equity checks driving above-average growth prior to the big step-up in DPS growth also account for the near-term growth). We see a potential for continued outperformance in the event all projects reach in-service as desired in the ~2018 period.

Figure 78: AES EPS estimates

	2015A	2016E	2017E	2018E	2019E
UBS EPS estimates	1.22	1.05	1.16	1.36	1.56
EPS Growth	-6.1%	-14.3%	10.6%	17.6%	14.5%
Guidance (Low)		0.95	1.12	1.25	
Guidance (High)		1.05	1.16	1.35	

Source: Company Filings, FactSet, and UBS Estimates

Our full valuation

We reflect market multiples for the businesses below off the latest US P/E multiples of regulated utilities and IPPs.

Figure 79: SOP View for AES – Part I

Sum of the Parts Analysis - Hedged Analysis - UBSe								
Latin America Listed Subsidiaries						Low	Base	High
Listed Subsidiaries	AES Tiete (Common, GETI3)	AES Tiete (Pfd, GETI4)	AES Eletropaulo (Common,	AES Eletropaulo (Pfd, ELPL4)	AES Gener			
UBS Price Target	20.00	20.00	7.26	8.00				
Current Share Price	13.20	14.55	6.16	6.79	319.67			
% Upside	52%	37%	18%	18%				
Ownership %	32.96%	14.94%	35.95%	3.41%	67.00%			
Shares O/S	197	184	67	101	8,070			
F/X Rate	3.61	3.61	3.61	3.61	688.20			
Market Value Stake	238	111	41	6	2,512		2,907	
UBS-Implied Equity Stake	360	152	48	8	2,512		3,079	
Premium PN/ON	10%		10%		Brazil		568	0.86189021
Shares Outstanding				reduce o		659	659	659
Implied Equity Value of Foreign Listed Subsidiaries (per Share)						4.67	4.67	4.67
AES Gener						*$3.81*	*$3.81*	*$3.81*
AES Tiete						*$0.78*	*$0.78*	*$0.78*
AES Electropaulo						*$0.08*	*$0.08*	*$0.08*
Latin American Utilities	2016 EBITDA	EV/EBITDA Multiple				Enterprise Value		
						Low	Base	High
Sul	0	0.0x	0.0x	0.0x		-	-	-
El Salvador	76	5.0x	6.0x	7.0x		378	453	529
Total LatAm Utilities (Non-Listed) EV	*76*	*5.0x*	*6.0x*	*7.0x*		*378*	*453*	*529*
Net Debt								
Sul - Equity Infusion Pending Sale of Company							75	
El Salvador							(239)	
Total LatAm Utilities Equity Value						214	289	365
Shares Outstanding						659	659	659
Total LatAm Utility Value Per Share (Non-Listed)						$0.32	$0.44	$0.55
Sul						*$0.11*	*$0.11*	*$0.11*
El Salvador						*$0.00*	*$0.33*	*$0.44*
	2016 EBITDA	EV/EBITDA Multiple				Enterprise Value		
Latin American Generation						Low	Base	High
Private Subsidiaries								
Uruguaiana CCGT	1	5.0x	6.0x	7.0x		7	9	10
Argentina Generation Portfolio	176	5.0x	6.0x	7.0x		879	1,055	1,231
Panama Generation Portfolio (AES Interest)	181	5.0x	6.0x	7.0x		907	1,089	1,270
Panama CCGT Expansion (Equity Investment)							250	
Dominican Republic Portfolio	162	5.0x	6.0x	7.0x		808	969	1,131
Total LatAm Generation (Non-Listed) EV	*520*	*5.0x*	*6.5x*	*7.0x*		*2,601*	*3,372*	*3,642*
Net Debt								
Argentina Generation Portfolio							(201)	
Panama Generation Portfolio							(543)	
Dominican Republic Portfolio							(329)	
Total LatAm Generation Equity Value						1,529	2,299	2,569
Shares Outstanding						659	659	659
Total LatAm Generation Value Per Share (Non-Listed)						$2.32	$3.49	$3.90
Uruguaiana CCGT						*$0.01*	*$0.01*	*$0.02*
AES Argentina						*$1.03*	*$1.30*	*$1.56*
AES Panama						*$0.55*	*$1.21*	*$1.10*
AES Dominican Republic						*$0.73*	*$0.97*	*$1.22*

Source: Company Filings, FactSet, and UBS Estimates

Figure 80: SOP View for AES – Part II

North American Utilities					Enterprise Value		
DPL	2017 Net Income		P/E Multiple		Low	Base	High
T&D Utility	68	17.5x	18.5x	19.5x	1,194	1,263	1,331
	Peer Multiple =		*19.0x*				
	Premium/Discount =		*-0.5x*				
Add: Back Hypothetical Debt					650	650	650
T&D Utility EV					1,844	1,913	1,981
	2016 EBITDA (Gen)						
Generation (excludes ESP uplift)	23	6.0x	7.0x	8.0x	136	159	181
DPL-ER	24	4.0x	5.0x	6.0x	96	120	144
Merchant EV					232	279	325
ESP Rates (Nonbypassable, NPV) - Estimated Contribution @ 50% Prob					87	87	87
Total DPL Debt (DP&L and Inc.)					(1,922)	(1,922)	(1,922)
DPL Equity Value					241	356	471
	2017 Net Income		P/E Multiple				
IPL (Indianapolis Power & Light)	117	18.5x	19.0x	20.0x	2,163	2,221	2,338
	Peer Multiple =		*19.0x*				
	Premium/Discount =		*0.0x*				
IPALCO Ownership post-Selldown					70%	70%	70%
AES' Equity Value in IPL					$1,514	$1,555	$1,637
Total US Utility Equity Value					$1,514	$1,555	$1,637
Shares Outstanding					659	659	659
Total US Utility Value Per Share					$2.30	$2.36	$2.48
DP&L (Dayton Power & Light)					*$0.37*	*$0.54*	*$0.71*
IPL (Indianapolis Power & Light)					*$2.30*	*$2.36*	*$2.48*

Source: Company Filings, FactSet, and UBS Estimates

Figure 81: SOP View for AES – Part III

European Generation	2016 EBITDA	EV/EBITDA Multiple			Low	Base	High
Private Subsidiaries							
AES Bulgaria (Maritza Lignite Plant)	213	4.0x	5.0x	6.0x	850	1,063	1,275
Kazakhstan	61	6.0x	7.0x	8.0x	366	427	488
UK Gen (Ballylumford CCGT and Kilroot Coal)	43	6.0x	7.0x	8.0x	256	299	342
Jordan (CCGT)	28	5.0x	6.0x	7.0x	139	166	194
Total European Generation EV	*349*	*4.7x*	*5.7x*	*6.7x*	*1,642*	*1,991*	*2,340*
Net Debt							
AES Bulgaria (Maritza Lignite Plant)						(589)	
AES Hungary (Tisza II Plant)						-	
Kazakhstan						(29)	
UK Generation (Ballylumford CCGT and Kilroot Coal)						(1)	
Jordan (CCGT)						(372)	
Total Net Debt						(1,151)	
Total European Generation Equity Value					614	964	1,313
Shares Outstanding					659	659	659
Total European Generation Value Per Share (Non-Listed)					$0.93	$1.46	$1.99
AES Bulgaria (Maritza Lignite Plant)					*$0.40*	*$0.72*	*$1.04*
AES Hungary (Tisza II Plant)					*$0.00*	*$0.00*	*$0.00*
Kazahkstan					*$0.51*	*$0.60*	*$0.70*
UK Generation (Ballylumford CCGT and Kilroot Coal)					*$0.39*	*$0.45*	*$0.52*
Jordan (CCGT)					*-$0.35*	*-$0.31*	*-$0.27*
Asian Generation	2016 EBITDA	EV/EBITDA Multiple			Low	Base	High
Private Subsidiaries							
Philipines (Masinloc), 51% Interest	55	6.0x	7.0x	8.0x	331	386	441
Masinloc Expansion (Equity Investment)						150	
Vietnam (Mong Duong), in-service	137	7.0x	7.0x	7.0x	961	961	961
Sri Lanka (Kelantissa)	27	6.0x	7.0x	8.0x	161	187	214
Total European Generation EV	*219*	*6.6x*	*7.7x*	*7.4x*	1,453	1,684	1,616
Net Debt							
Philipines (Masinloc), 51% Interest						(204)	
Vietnam (Mong Duong), In-service in 2016 - $809Mn 51% owned						(646)	
Sri Lanka (Kelantissa)						-	
Total Net Debt						(850)	
Total Asian Generation Equity Value					602	834	766
Shares Outstanding					659	659	659
Total Asian Generation Value Per Share (Non-Listed)					$0.91	$1.27	$1.16
Philipines (Masinloc)					*$0.19*	*$0.50*	*$0.36*
Vietnam (Mong Duong), in-service in 2016					*$0.48*	*$0.48*	*$0.48*
Sri Lanka (Kelantissa)					*$0.24*	*$0.28*	*$0.33*

Source: Company Filings, FactSet, and UBS Estimates

Figure 82: SOP View for AES – Part IV

North American Generation	2016 EBITDA	EV/EBITDA Multiple			Low	Base	High
Southland (Contracted Gas in CA) - Re-contracte	119	6.0x	7.0x	8.0x	711	830	949
Mountainview	5	6.0x	7.0x	8.0x	30	35	40
Warrior Run (Contracted Coal in MD): Thru 2030	66	6.0x	7.0x	8.0x	398	464	530
Shady Point (Contracted Coal in OK)	27	6.0x	7.0x	8.0x	162	189	216
Hawaii (Contracted Coal in HI)	47	5.0x	6.0x	7.0x	235	282	329
Puerto Rico (Contracted Coal in PR)	148	5.0x	6.0x	7.0x	740	887	1,035
Merida (Contracted CCGT in Mexico)	37	6.0x	7.0x	8.0x	222	259	296
TEG/TEP (Contracted Coal in Mexico)	77	6.0x	7.0x	8.0x	465	542	620
Total North American Generation EV	526	*5.6x*	*6.6x*	*7.6x*	2,963	3,489	4,015
Net Debt							
Southland						(152)	
Warrior Run						(103)	
Shady Point						(39)	
Hawaii						(232)	
Puerto Rico						(446)	
TEG/TEP						(300)	
Total Net Debt						(1,272)	
Total North American Generation Equity Value					1,691	2,218	2,744
Shares Outstanding					659	659	659
Total North American Generation Value Per Share (Non-Listed)					$2.57	$3.37	$4.16
Southland					*$0.85*	*$1.03*	*$1.21*
Warrior Run					*$0.45*	*$0.55*	*$0.65*
Deepwater					*$0.00*	*$0.00*	*$0.00*
Red Oak					*$0.00*	*$0.00*	*$0.00*
Ironwood					*$0.00*	*$0.00*	*$0.00*
Shady Point					*$0.19*	*$0.23*	*$0.27*
Hawaii					*$0.00*	*$0.08*	*$0.15*
Beaver Valley					*$0.00*	*$0.00*	*$0.00*
Puerto Rico					*$0.45*	*$0.67*	*$0.89*
TEG/TEP					*$0.25*	*$0.37*	*$0.49*

Source: Company Filings, FactSet, and UBS Estimates

Figure 83: Summary SOP View for AES

Summary SOP Valuation for AES Corp		% Owned by AES			Low	Base	High
Listed Latin American Subsidiaries					$4.67	$4.67	$4.67
Latin American Utilities (Unlisted)					$0.11	$0.44	$0.55
Latin American Generation (Unlisted)					$2.31	$3.48	$3.88
North American Utilities					$2.30	$2.36	$2.48
North American Generation					$2.18	$2.92	$3.65
Asian Generation					$0.91	$1.27	$1.16
European Generation					$0.94	$1.46	$1.98
Summary SOP Valuation for AES Corp					Low	Base	High
Total Subsidiaries Equity Value					$13.43	$16.60	$18.40
Other Adjustments (Parent Debt, etc)							
Parent Adjusments, Debt, and Corp/Other						(3,764)	
Shares Outstanding						659	
Parent Debt Oustanding and Cost Drag per Share						($5.71)	
AES Corp Total Equity Value per Share					$8	$11	$13
Parent Adjustments, Debt, Etc							
	2016 EBITDA		EV/EBITDA Multiple				
Corp/"Other" businesses (EBITDA)	65	6.0x	7.0x	8.0x	$389	$454	$519
	2017 Net Income						
Equity Investments	35	7.0x	8.0x	9.0x	$245	$280	$315
NPV of NOLs						$238	
Other Non-Recourse Debt (Corp/Other)							
Other Wind Projects, Euro/African Utes, etc						($104)	
Recourse Debt *(using latest reported 10K numbers)*							
Unsecured Notes						($5,015)	
Less Current Maturities						$0	
Secured Debt / Term Loans						$0	
Total Recourse Debt						($5,015)	
Total Cash (incl. Subsidiaries), FY15						$1,262	
Exclude Subsidiary Cash, FY15						($755)	
Net Debt (FY15)						($4,508)	
Parent FCF (mid point of guidance)						$575	
Investment in Subsidiaries						-$330	
Shareholder Dividends						-$290	
Expected Share Buyback						-$79	
Incremental Cash Generation FY15 to FY16						-$124	
Parent Adjusments, Debt, and Corp/Other						(3,764)	
Shares Outstanding (2016e)						659	
Parent Debt Oustanding and Cost Drag						($5.71)	
AES Corp Total Equity Value per Share					$8	$11	$13

Source: Company Filings, FactSet, and UBS Estimates

Brazil: Exiting the Volatility

Timing on the asset divestment is predicated on completion of the 2016 Tiete contract expiration, reducing the risk of bilateral renegotiation. Following the success of the Sul sale announcement around 1Q, mgmt would like to be decisive on any further divestment if it were to occur, referring to the Eletropaulo business; shares are traded publically and mgmt rules out any sale via open market. Given the market value of $75Mn (~$0.10/sh in SOTP value) and its contribution of just $0.01 in EPS, we believe a sale would appear an easy opportunity to de-correlate the equity (it consolidates the segment given operational control despite a 16%

stake). The mixed message remains tied to its commitment to re-lever its Tiete subsidiary to acquire more generation in the country. While nominal real exposure would still likely decrease by ~$1Bn despite re-leveraging, questions about the companies underlying exposure to the Americas remain. Despite the de-emphasis on Brazilian F/X currency, we estimate at least ~40% of the company's equity value is tied to this region via both listed and unlisted subsidiaries.

DPL: Getting to a better place following FE's footsteps

We are increasingly confident in positive resolution of its pending petition before the PUCO for an extended ESP. The PUCO has repeatedly clarified its intention to ensure the financial health of the states' utilities to enable their continued corporate operations in-state as well as support the viability of their underlying asset base. Despite the recent rejection of DPL's existing ESP by the Ohio Supreme Court (and associated ~$0.10/sh contribution to 2016, with a ~$0.05 impact if ultimately unwound), we don't expect a guidance shift yet – nor should investors read meaningfully into the willingness of the PUCO to provide further assistance under its pending ESP for implementation in 2017.

Tiete: Looking to re-lever via non-Hydro assets still.

Prices have evolved substantially in recent months as hydrology has improved, despite still being below average, with prices of late towards 75Rs/MWh, from north of 150Rs/MWh. Mgmt remains confident it can execute on a re-leveraging of the business with its existing debt capacity of ~2Bn Rs. With declining interest costs, mgmt is particularly constructive on cheaper costs of financing. The emphasis has been away from hydro assets towards non-hydro fossil fuel fired and renewable assets, seemingly with a focus on acquisition. This is an important shift in strategy; and contrasts from previous comments in 2015 which focused on potentially expanding its existing hydro portfolio to adjacent systems to capture synergies. The volatility arising from recent year swings in hydrology appear to have become intolerable for AES Corp overall as it seeks to reduce its key variability. The key consideration in re-leveraging the company remains the added sensitivity to Brazilian Real for the equity.

Alto Maipo: Big Hydro Construction Underway albeit a tad behind

AES mgmt is confident the SIC (Central) Chilean market will remain intact despite construction challenges around the deep tunneling required. Based on AES' last quarterly call, the project delay amounts to 1Q, with the project being gradually put in-service from 2H18 through 1H19. The project includes 60-miles of mining through the mountains to enable adequate hydrological flows. Among large-projects, we continue to monitor timing related to the exact magnitude of 2018 and 2019 y/y growth.

DPL: Get Resolution First, then Look at Commodity Exposure?

The company had previously contemplated a sale of its DPL business, however, has so far held off given the need for clarity around its ESP. While it suffered a recent setback at the Ohio Supreme Court, we remain confident in an outcome supportive of the company from the PUCO. In the near term, we do *not* expect mgmt to reduce EPS guidance on the Supreme Court rejection– neither for the remaining 2016 EPS benefits pending clarification of the Court's implementation before the PUCO as well for potential benefits in 2017+ as this is a separate and distinct filing pending before the commission for subsequent relief, technically unrelated to the rejected ESP structure rejected by the Court. Rather, we would

expect the PUCO and DPL to respond with a similar proposal as illustrated in PUCO Staff's latest novel approach embedded in its testimony before the FirstEnergy case in recent weeks, in which a distribution modernization rider, requiring installation of smart meters, would act as the vehicle for additional revenues, funnelling these back to the parent.

Getting More Questions on Coal: What is the Strategy from here?

Investors remain quite concerned over its overall exposure unlike previous meetings: Among the more notable shifts in the focus for the equity has been greater focus on AES' coal portfolio, with ~40% on a MW basis. With an emphasis on pruning the lower quality assets of the portfolio, the asset divestment strategy would appear to drive a wider eventual trend; for instance, DPL, its largely zero-equity value subsidiary contains ~7% of total capacity (~2GW). Further, we believe many of the remaining coal assets, located in less ideal regulatory jurisdictions, may indeed be the first divestment targets as mgmt looks to continue to prune its underlying portfolio. Finally, mgmt states the latest two coal plants under development in the Philippines and India are the last two likely ever developed by the company.

Returns: "Bracketed by the I's"

Mgmt continues to see returns largely within a 10-20% ROE range, with an average of ~15% across its contemplated growth prospects. The focus remains on incremental projects and selling down incremental stakes to maximize its return. Financial partners appear to be the likely partnership, with 30-40% stakes in AES' projects. Mgmt remains keen it be the operator of future projects. This would appear to add 1-2% to overall earned ROEs.

AES: More California Solar projects, but that's it for now.

Mgmt continues to quietly grow its solar business, with ~$40 Mn of equity investments in Californian solar in 2016 alone. We note its renewable efforts remain relatively low key following its wider divestment of these businesses earlier in Europe and China. While it appears the strategy to address its more coal heavy portfolio is a clear strategic necessity, underlying growth ambitions in renewables remain more modest, seeing its cost of capital as largely too high relative to many peers to compete for lower return projects. We note this project is an example of a litany of smaller growth projects underway at the company to contribute to 8-10% EPS growth contemplated in 2017 and 2018 off 2016 lows (just 5% of EPS growth is contemplated with cost cutting exercises and the wider macro backdrop).

Adapting Coal to the Modern Grid? Developing More Flexible Coal.

A strategic priority appears to improve the operational characteristics of its existing coal portfolio to adapt to growing intermittency across grids, globally. The effort would appear to complement efforts to deploy its battery technology across a greater geographic footprint. We look to learn more on steam turbine flexibility in coming quarters – and a consistent theme across a wider range of older fleets (both coal and nuclear) to deal with greater renewable dispatch.

Argentina: An Eventual Value Proposition?

With EPS today at ~$0.07 under the existing price caps in Argentina, mgmt has been striking an increasingly confident tone on eventual lifting of such price caps. At a contribution of $90 Mn in PTC, this would imply ~$30/kW-year in PTC margin on its 3GW portfolio. While no specific timetable or increased profitability targets

are contemplated, mgmt specifically points to the thin profitability of its hydro portfolio in particular.

Where is the Growth? Three Themes.

LNG and Gas Generation: A Major Americas Player

We look for management to stress this theme within its story all the more in coming quarters. Panama has a 10-year CCGT contract for 350 MW. The CCGT would use only ~1/4 of the total LNG terminal capacity, but ROEs would improve meaningfully (above 15% average targeted) via effective marketing to other local gas plants as well as principally ship bunkering through the Panamanian Canal. Cruise Lines would appear the focal point to 'green' their image and meet emission requirements for sailing to coastal waters of several countries. Total investment is $900 Mn-$1 Bn. The goal remains to limit commodity risk, albeit the key risk appears to be volumetric commitments. This latest Panamanian effort complements the meaningful footprint of its existing LNG import facility into the Dominican Republic. We estimate this segment produces EBITDA of ~$100 Mn.

Overall, Central America and Mexico appear the most meaningful source of incremental project growth, all of which focuses on transitioning the region away from expensive diesel and other refined oil products for power generation (enabling aggregate cost reductions to consumers despite meaningful spend opportunity tied to bringing gas into the region). In terms of next data points, we look for tangible developments on new gas plants under its new partnership with Grupo Bal. While mgmt is indeed concerned over the level of competition exhibited in the Mexican market place thus far, it appears confident it can succeed in gas plant development (rather than for instance renewable assets).

Battery Storage:

Small wins continue, but still quite a modest piece of the story. Mgmt remains a leader in this market, with a focus on development to both its own sites as well as deployment for other utilities and IPPs. It has recently been awarded a 40MW ratebase storage project within its core IPALCO (Indianapolis) subsidiary. Mgmt indicates it has a variety of interests for similar deployments with adjacent utilities in which AES will develop and deploy its integration wrap around standard battery chemistries provided from manufacturers such as LG Chem. Mgmt is meaningfully more bullish on battery deployment across emerging markets than OECD countries, where existing reliability is typically much better. We look for the company to explore adjacent deployments at existing sites across various islands such as the Dominican Republic and Puerto Rico where reliability is clearly less than ideal.

Among the further questions in the battery business is whether AES will meaningfully pursue smaller-sized 'economic' C&I market in addition to focusing on utility-scale deployment opportunities for both T&D utilities as well as generation complements.

Bottom Line: While this business continues to show positive developments, its overall earnings to the company remain pennies overall. We believe AES will remain at the front-edge of storage deployment given its existing IT wrap; in this regard its battery effort resemble both self-development and an internal specialized E&C function.

Dividend Growth tied to Parent FCF Growth:

Looking to informally target a dividend policy of 45-50% of Parent FCF in the long term; the goal of at least 10% dividend growth through 2018 is consistent with the at least 10% DPS growth. We note this pace of Parent FCF growth and in turn DPS growth will clearly moderate thereafter, albeit we look for a more formal target as the CAGR is rolled forward with 4Q results next February. Mgmt continues to target a further improvement in its credit quality towards IG-like metrics, desiring at least BB+ metrics in coming years. We think an improvement in underlying credit quality will also be driven by the continued pruning and de-risking of the portfolio. We note mgmt. continues to prefer contracted generation rather than utility operations, in contrast to many US peers, as it perceives less overall risk in single contracted generation assets rather than wider customer-facing utilities in emerging markets.

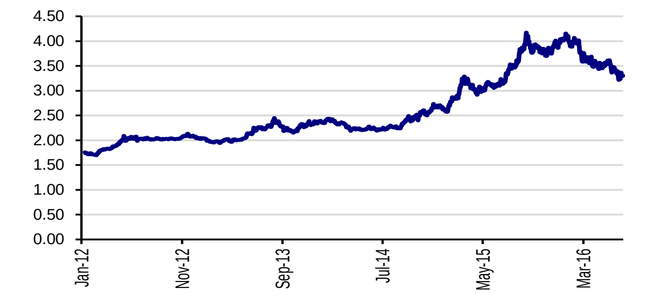
Where is the Portfolio Repositioning? Still Focused on Americas.

We expect the company to continue to execute on a repositioning in its portfolio towards the Americas, with a focus on growth in Central and North America. We would expect divestments to remain oriented towards Europe and Asia, consistent with recent sales. The one exception appears to be Brazil where historical correlations appear to have a disproportionate impact on shares.

How has the Real done?

We emphasize the Brazilian currency appears to have found a bottom and fostered renewed confidence in the AES story. We perceive a positive shift in sentiment could well continue into 2Q results as a positive MtM on commodities and the macro backdrop remains an important opportunity. We flag the recovery in Brazilian currency relative to USD remains among the key improving factors.

Figure 84: F/X Rate for USD / Brazilian Real

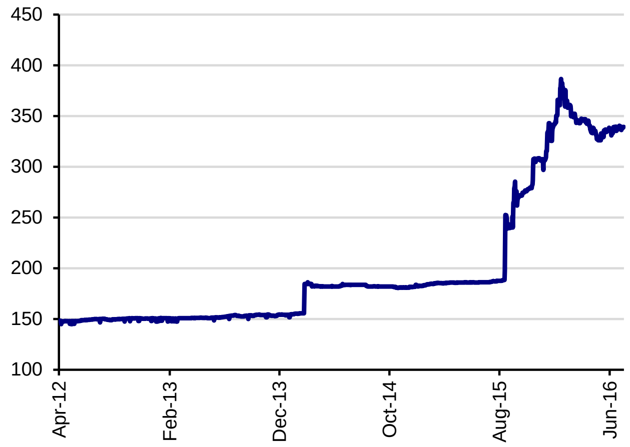


Source: FactSet

Figure 85: F/X Rate for USD / Euro

Source: FactSet

Figure 86: US Dollar per Kazakhstan Tenge



Source: Factset

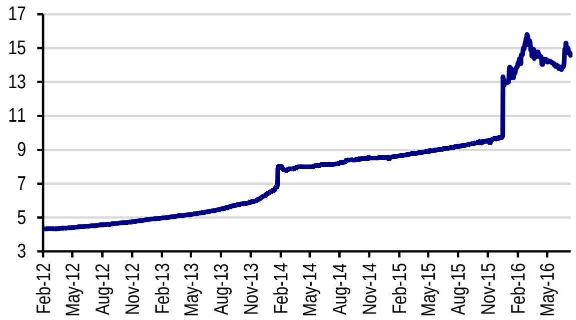
Figure 87: US Dollar per GBP

Source: Factset

Figure 88: US Dollar per Colombian Peso

Source: Factset

Figure 89: F/X Rate for USD / Argentine Peso



Source: Factset

But What's the Impact on the Quarter from Macro?

Despite the BRL recovery, the latest impact from the sharp move in the British Pound (via its Northern Ireland exposure) appears to be the primary headwind to shares. We emphasize the overall outlook appears to have improved modestly QoQ, a nice departure from prior consistent negative revisions.

Figure 90:F/X and Commodity Moves – since 1Q Call: Not much, but slightly *positive!*

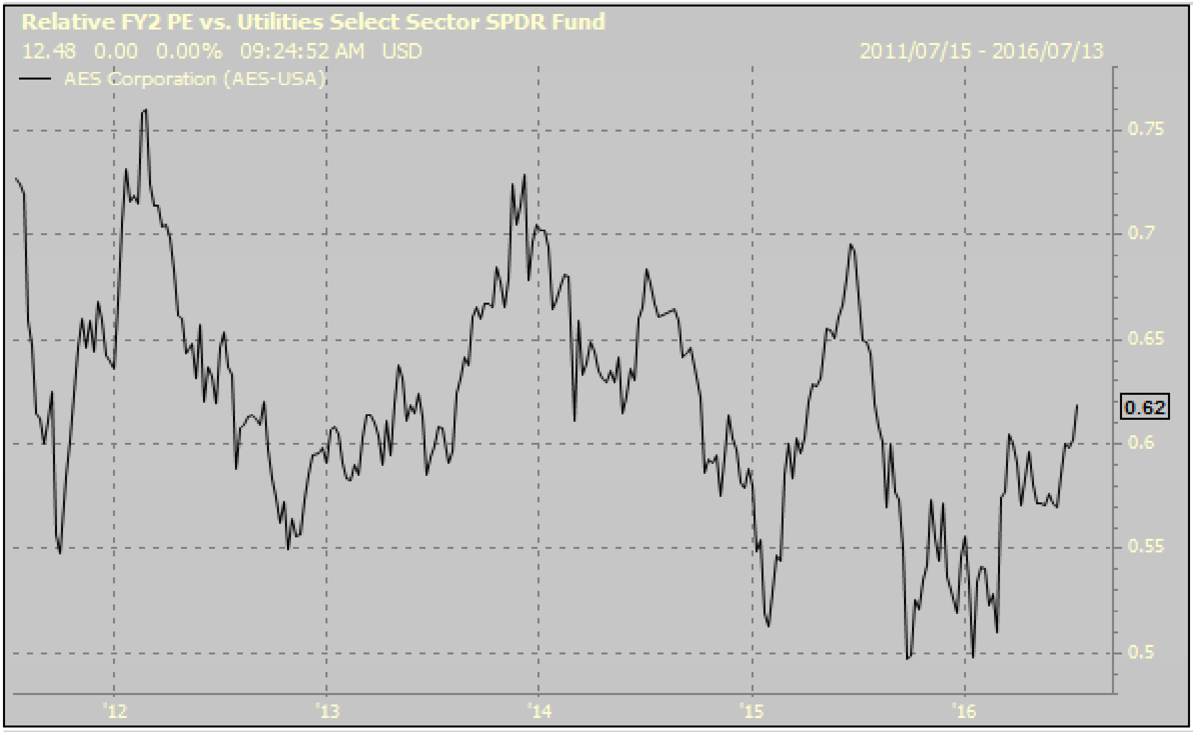
FX Exposure	Argentine Peso	Brazilian Real	Euro	British Pound	Kazakhstan Tenge	Colombian Peso	
Average Rate assumed for 2016 as on 4/30/2016	15.43	3.56	0.87	0.68	341.10	2911.00	
Rate as on 7/12/2016	14.57	3.30	0.90	0.75	339.37	2918.71	
% change	-5.6%	-7.4%	3.9%	10.2%	-0.5%	0.3%	
Correlation	-ve	-ve	-ve	-ve	-ve	-ve	
Assumed sensitivity	0.005	0.005	0.005	0.005	0.005	0.005	
2016 EPS impact	0.0028	0.0037	-0.0020	-0.0051	0.0003	-0.0001	
2016 EPS Sensitivity	0.27%	0.36%	-0.19%	-0.49%	0.02%	-0.01%	
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 4/30/2016	45	47	47	48	2.50	0.45	30
Rate as on 7/12/2016	39.5	57.7	46.8	48.5	2.7	0.5	32
% change	-12.2%	22.8%	-0.4%	1.0%	9.2%	-0.2%	5.3%
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		-0.0046		0.0003		0.0034	0.0132
2016 EPS Sensitivity		-0.44%		0.03%		0.33%	1.27%
Total MtM Impact to EPS		MtM currency impact	MtM commodity impact	Total New Impact (EPS)	Total New Impact ($ Mn's)	% Change in EPS	
2016 EPS UBSe		-0.0005	0.0123	0.01	12	1.1%	

Source: Company Filings, FactSet, Bloomberg, UBS estimates

What we think of shares now?

Following the recent rally in shares, back to multi-year relative P/E highs vs. the XLU (still at a 38% discount on FY2 basis) and at a relatively strong historical P/E vs. AES' stand-alone multiple, the question is can the rally continue? We see potential for resolution in Ohio, and any further portfolio divestment (eg- Brazil) as boding well for the company through the balance of 2016. We emphasize from a fundamental perspective, shares appear to be exceeding recent historical multiples *even* when adjusting for recent improvement in US utility multiples (eg—its outpacing even the substantial recovery in utilities of late). Beyond its exposure to Latam, we attribute its recent outperformance to a supportive market backdrop to highly leveraged companies. We note few investors appear to appreciate the modest parent leverage, taking the company's EV on a consolidated basis (and in turn reflecting quite leveraged metrics.) This appears a misperception to the equity story. We note an emerging focus for mgmt. to simplify its capital structure as part of its ongoing asset pruning efforts.

Figure 91: AES 2 Yr Fwd P/E relative to XLU

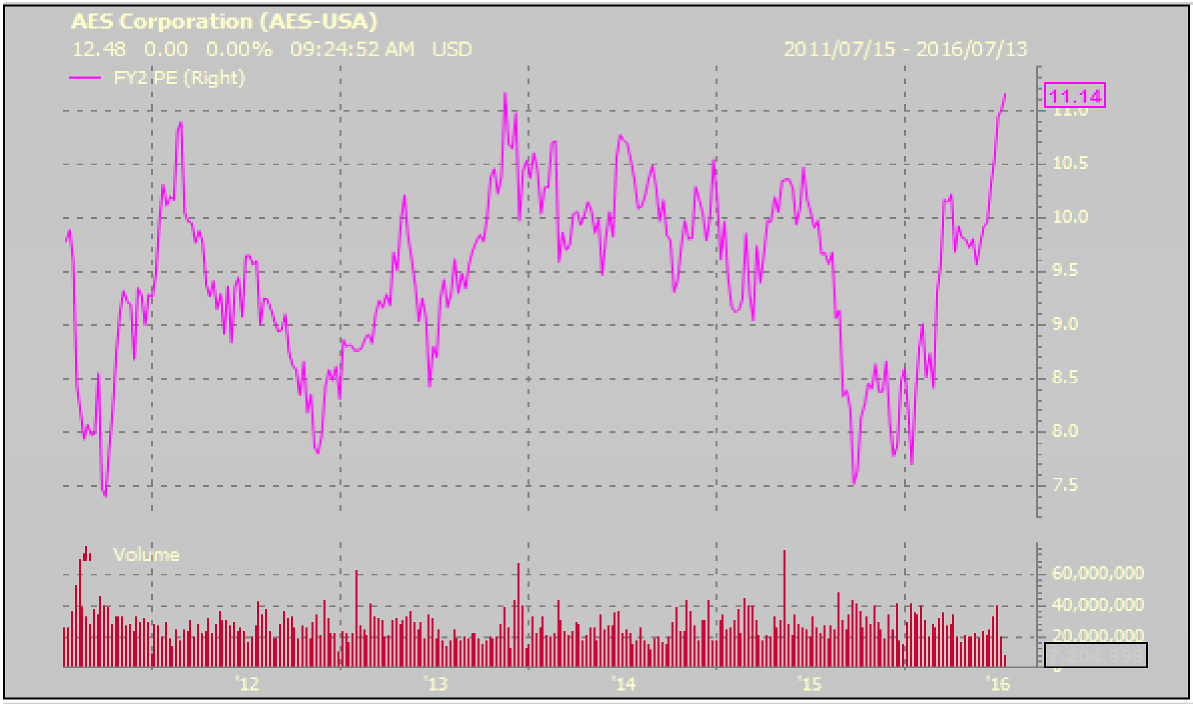


Source: , FactSet

What about on an absolute basis? Multiple has improved dramatically.

We emphasize shares are now trading at a 5-years high

Figure 92: AES 2 Yr Fwd P/E

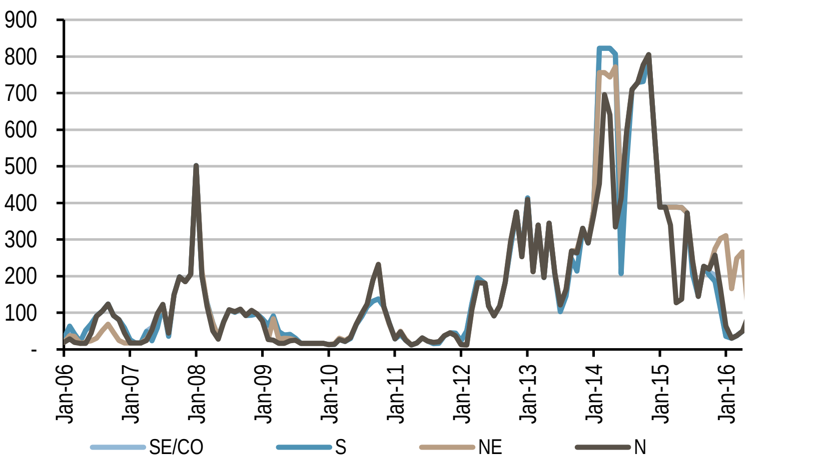


Source: FactSet

Brazil Prices Returning to Nominal Levels

We emphasize power prices have returned to modest levels. In contrast to the hydrological concerns of recent years, the latest prospects are concerning as ability to replace hedged power prices are challenged.

Figure 93: Brazilian spot market prices remain volatile (R$/MWh, in real terms)

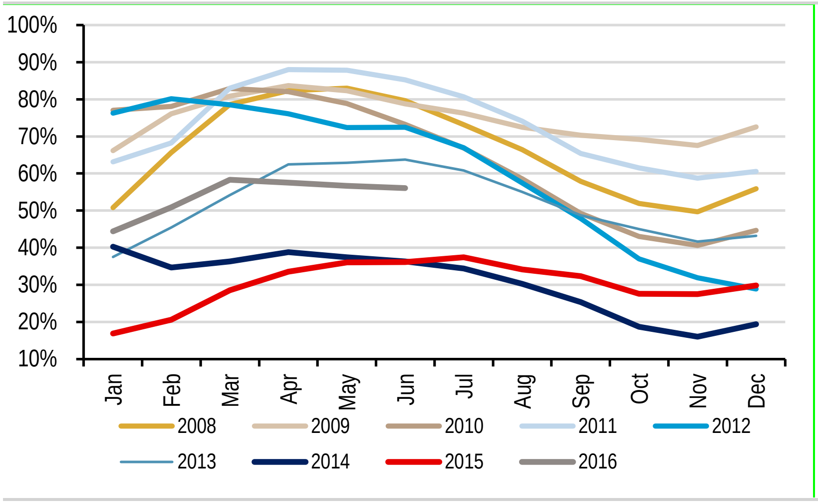


Source: CCEE, UBS

Hydrology Update

Reservoir levels today are better than one year ago but this is due to high level of dispatch of thermoelectricity plants.

Figure 94: Brazil hydrology: reservoir level data

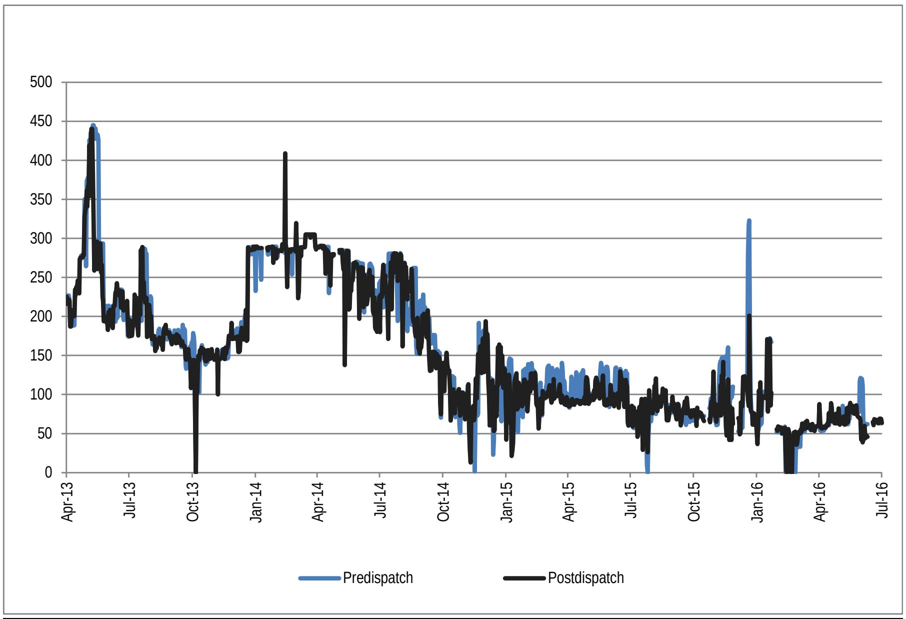


Source: ONS, UBS estimates

Panamanian Hydro Disclosures: Remains in Check

Following significant scrutiny in 2013 of hydro levels across Central America, we include recent spot prices following the significant drought conditions experienced recently. We emphasize AES' efforts in the country to add LNG capacity creates a more meaningful exposure to potential added demand should hydrological conditions soften in the future. They remain on track for the time being.

Figure 95: Panama Spot Prices – Pre/Post-Dispatch (Generation MWh per Unit System) – Back at the lows



Source: Company reports

Underlying International Commodity Performance

Following the rally in Rotterdam coal prices, we ask whether the arbitrage with US coal prices is sustainable. With bulk shipping rates among the lowest in 30-years at just ~$6/t for this specific route per our UBS Shipping Analyst Spiro Dounis, this would appear to provide a clear potential for a demand pick up.

Figure 96: Rotterdam Coal ($/ton), International Coal Proxy

Source: FactSet

Figure 97: NYMEX CAPP Coal ($/ton), Domestic Coal Proxy

Source: FactSet

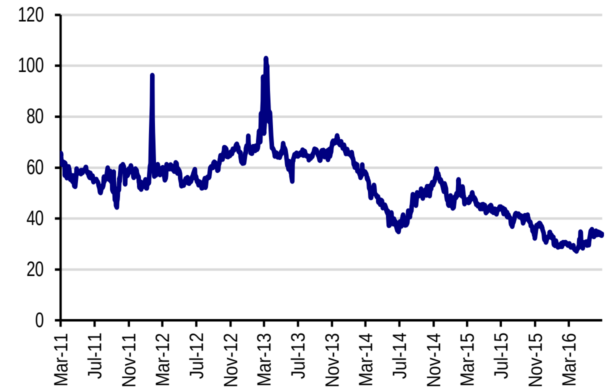
Comparing the Forward Gas Months: US vs. Europe

Henry Hub natural gas rose from August '13 lows of ~$3.23/MMBtu to a high of ~$6.15 on February 19th 2014. They have been declining steadily since then, however, 2Q16 observed reversal of gas prices and are trading ~ $2.73 as of now; down -2.1% on Y-o-Y basis. Meanwhile, European gas prices have experienced decline of -24% on Y-o-Y. 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 98: US Natural Gas (Hub), $/MMBtu Front Month

Source: FactSet

Figure 99: 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 $50 level at the moment; and were down -18% and -3.8% respectively on Y-o-Y basis. 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 100: Crude Oil (WTI), $/Bbl

Source: FactSet

Figure 101: Crude Oil (IPE Brent), $/Bbl

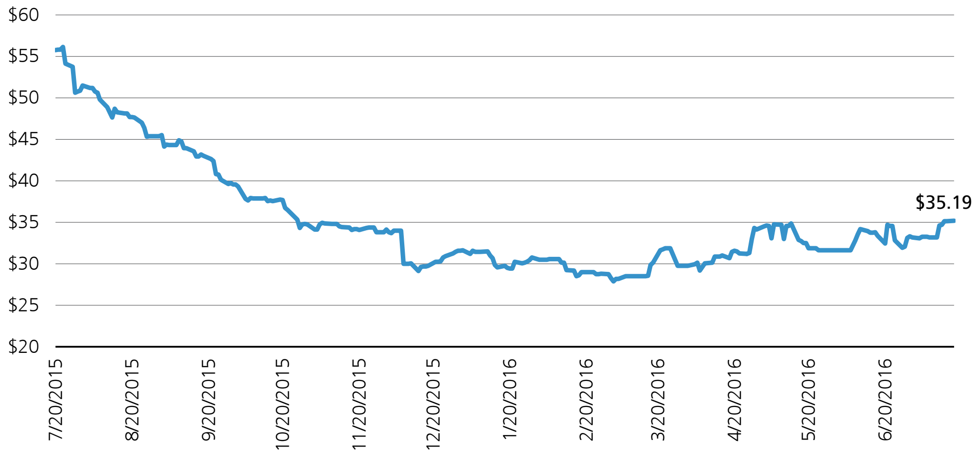
Source: FactSet

EFH (Unrated)

EFH Debt: Recovering with Gas

We include the latest quoted price for EFH 1st lien bank debt below; we see this as the most comparable entity to NRG equity in IPP landscape. We emphasize as the bankruptcy continues to edge towards plan confirmation, executives involved continue to express confidence on path towards eventual EFH restructuring re-emergence.

Figure 102: EFH Latest Bank Debt (Extended 2017 Term Loan): Recovering a Bit



Source: Bloomberg

EFH's initial post bankruptcy emergence paints a picture of substantial cost cuts
In its first public presentation of its outlook prior to emergence from bankruptcy, EFH painted an improved picture of its outlook, reflecting both existing but also prospective cost cuts to its SG&A cost structure to compete in the low power price environment in Texas. While clearly a constructive development to the company, we read this as a cautious datapoint for the wider potential for ERCOT recovery. Further, with a new mgmt set to take the helm, aspirations are for further cost cuts beyond those already reflected in the latest presentation. In particular further improvement in coal plant economics could be forthcoming as rail contracts and coal terms continue to reprice.

EFH disclosures also illustrate substantial profitability on Retail biz

Among the key positive surprises were meaningfully higher results on its TXU Energy business than previously projected. We perceive a wider concern in the ERCOT market that under-water generation assets are preserved through the extrinsic hedge they provide to highly profitable retail businesses, including TXU Energy and NRG. Disclosures are consistent with NRG in implying ~$30/MWh+ resi margins when applying more modest ~$5/MWh C&I margins; we continue to perceive meaningful risk tails to this business as migration from above-market contracts remains a meaningful risk to all incumbent electric retailers (for those who have yet to actively 'choose' to shop for their electric providers).

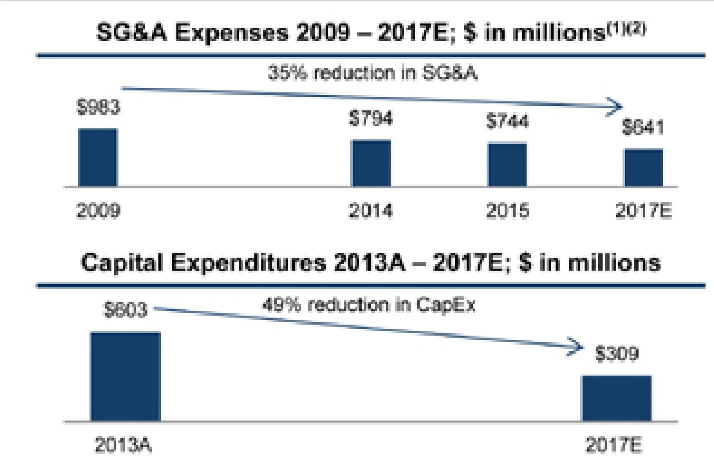
No discussion of legacy gas asset retirements either
Notable within the focus on generation in the slides released is limited discussion of the legacy gas steamer portfolio. We continue to see this as a regional-wide question, particularly acute for both NRG and EFH around what to do with largely money losing steam-fired gas turbines. While ideal candidates for retirement, their large size and meaningful hedge characteristics despite 10+ hour ramp times, we have yet to see much by way of retirements of late. Rather, the single asset that attempted to retire was put back on an RMR emergency contract by ERCOT.

Cost Structure Plans are Below Expectations; No Structural Shutdowns in Sight

Current TCEH plan suggests SG&A expense can shift down substantially and has already moved from ~$983M in 2009 to ~$744M in 2015. Current plan suggests ~$641M is achievable in 2017 – an incremental ~14% cost reduction in two years and even more ambitious in light of typical 2-3% wage inflation in the region. We view this as incremental confirmation that plant retirements are less likely imminently, further reinforced by ~50% capex cut from 2013A $603M driven by conversion to "seasonal operations that lower run times leading to reduced maintenance and total variable costs".

TCEH's Cost structure appears to target substantial cost reductions but does NOT include assumptions around plant shutdowns

Figure 103: Corporate Cost Cutting: Not Plants



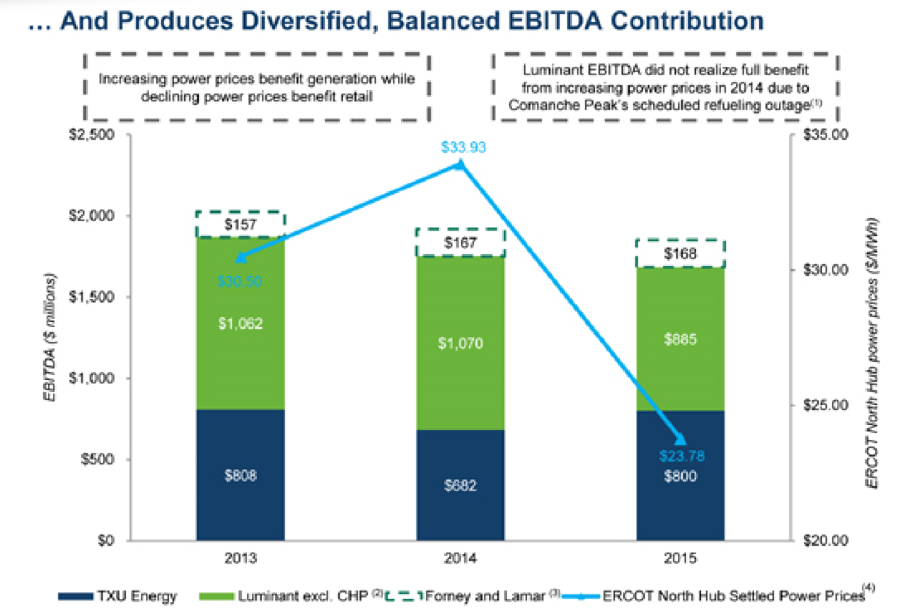
Source: Texas Competitive Electric Holdings Company July 12 Lender Presentation

Does a meaningful retail platform also limit retirement risk too?

In fact, balanced earnings stream appears to be a key focus for the new company – with TXU and Luminant complementing each other and providing insight into how the new company will function. Specifically, it appears management is most focused on maintaining diversification between retail and generation in order to act as a hedge against price spikes.

The wider question in the sector is just how much of a deficit are generators willing to take on via generation to support their highly lucrative retail operations? We read NRG's hesitancy to close plants in Texas as illustrative of this trend.

Figure 104: TCEH's focus on Diversified EBITDA Implies Value from Idle Plants

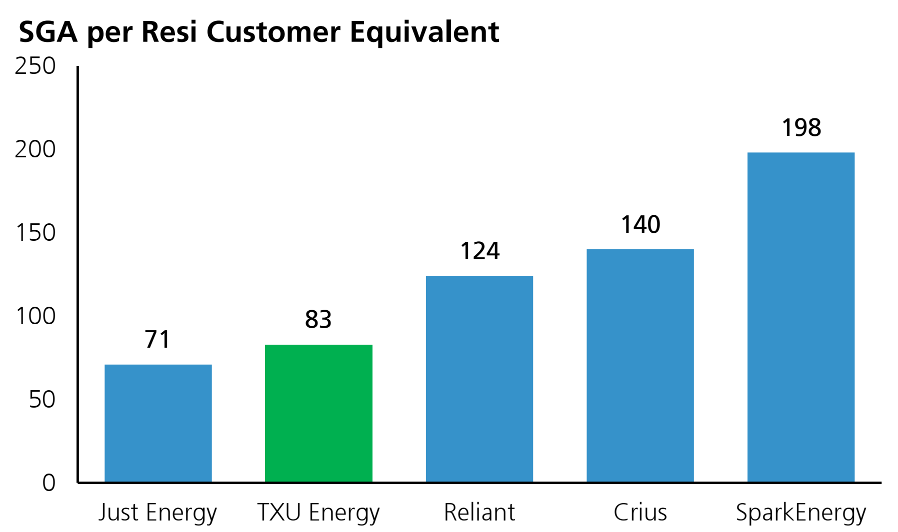


Source: Texas Competitive Electric Holdings Company July 12 Lender Presentation

Retail Margins Also Appear Supportive of Keeping Even Old Plants as a Hedge

~25% market share for TXU Energy in the retail space suggests TXU's substantial retail exposure (the largest marketshare of any single provider according to management estimates) implies Luminant's existing generation fleet is more 'sticky' than some had previously thought.

Figure 105: SG&A per Residential Customer



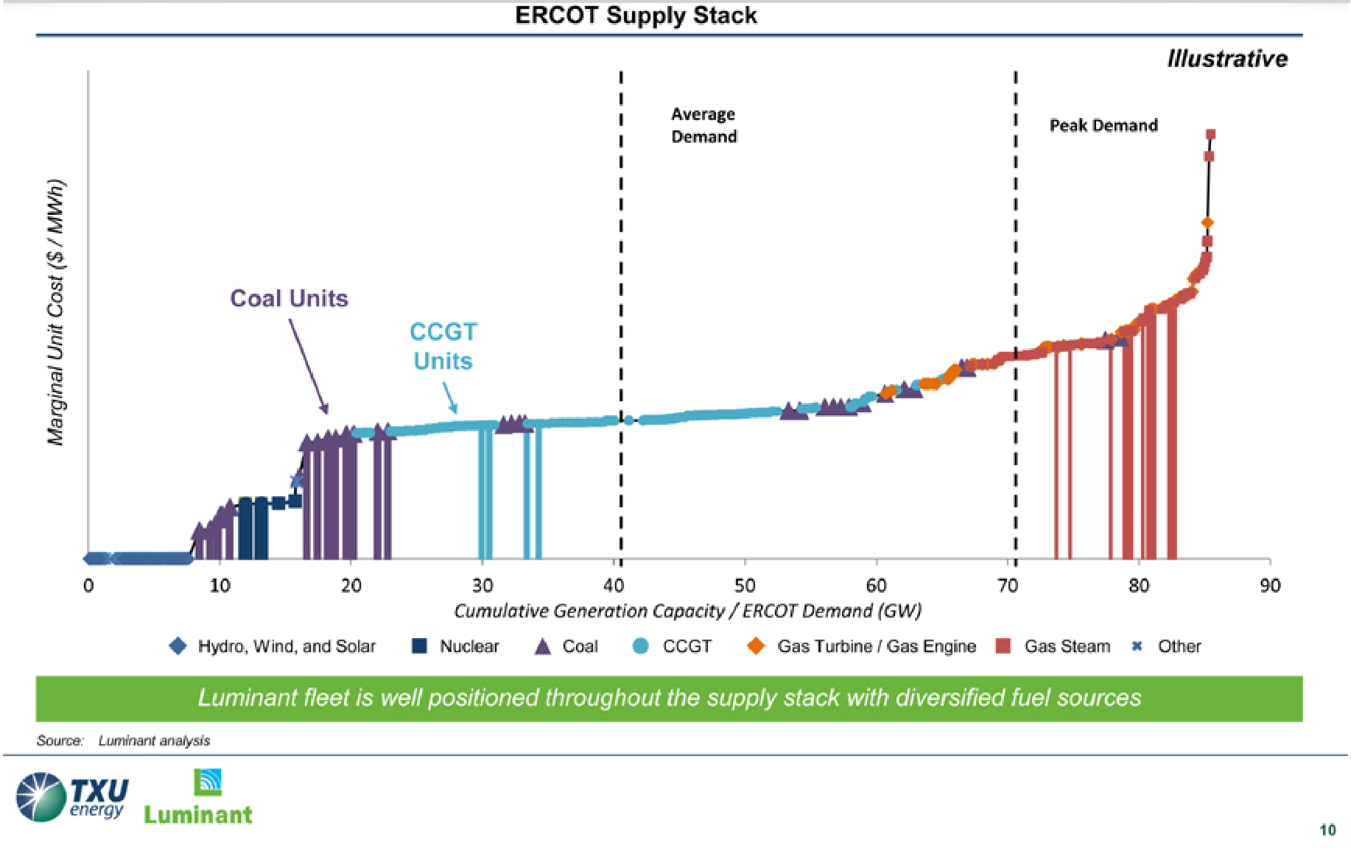
Source: Texas Competitive Electric Holdings Company July 12 Lender Presentation

So What is the Generation Fleet? It's meaningful to ERCOT Mix

Luminant owns ~16,760MW of generation, or ~20% of total ERCOT generation base of ~87.4GW. This positions the company well ahead of NRG (10.6GW), Calpine (9.4GW), Dynegy (4.7GW), and Exelon (3.5GW) in ERCOT. Further, the company's recent acquisition of Forney and Lamar positions it in a somewhat more

diversified way throughout the supply stack in ERCOT, which could allow more economic plants to help float peakers to balance the retail side of the business. The presentation below appears to show its coal units as still being 'in the money' relative to gas plants (albeit a specific date is not provided for commodity curves here in the deck).

Figure 106: Management's Assumed Supply Curve



Source: Texas Competitive Electric Holdings Company July 12 Lender Presentation

Retirements: The Three Oldest Plants Remain the Focus

While we note the company's newer units are actively operating, ~8 peakers are likely subsidized by the rest of the business. We have summarized the company's presentation below in a fleet overview. While Big Brown is the most concerning unit (with no scrubbers installed), the other plants appear to be a key part of the company's strategy exiting bankruptcy. Further scrutiny exists of the other old coal plants, Martin Lake and Monticello.

Figure 107: Luminant Portfolio

	Facility	Capacity	Capacity Fator (historic avg)	COD	Fuel	Tech
	Comanche Peak	2300	98%	1990/1993	Nuclear	
Seasonal	Big Brown	1150	77%	1971-72	Coal	ST
	Martin Lake	2250	66%	1977-79	Coal	ST
	Monticello	1880	39%	1974-78	Coal	ST
Newer Plants	Oak Grove	1600	87%	2010/2011	Coal	ST
	Shadow Unit 5	580	80%	2010	Coal	ST
	Forney	1912	54%	2003	Gas	CC
	Lamar	1076	60%	2000	Gas	CC
Simple Cycle and Peakers	Decordova	260	N/A	1990	Gas	CT
	Graham	630	N/A	1960/1969	Gas	ST
	Lake Hubbard	921	N/A	1970/1973	Gas	ST
	Morgan Creek	390	N/A	1988	Gas	CT
	Permian Basin	325	N/A	1988/1990	Gas	CT
	Stryker Creek	685	N/A	1958/1965	Gas	ST
	Trinidad	244	N/A	1965	Gas	ST

Total Nuclear	**2,300**
Total Coal	**7,460**
Total Nat Gas	**6,443**

Source: Texas Competitive Electric Holdings Company July 12 Lender Presentation

What other units in Texas?

Besides EFH, we remain focused on both DYN's pending acquisition of Colleto Creek and whether this smaller unit will be retired as part of the acquisition as well as Blackstone's Twin Oaks plants, a smaller mine-mouth lignite coal facility. Both would appear to be near breakeven.

But what to make of the legacy steamers and peakers too?

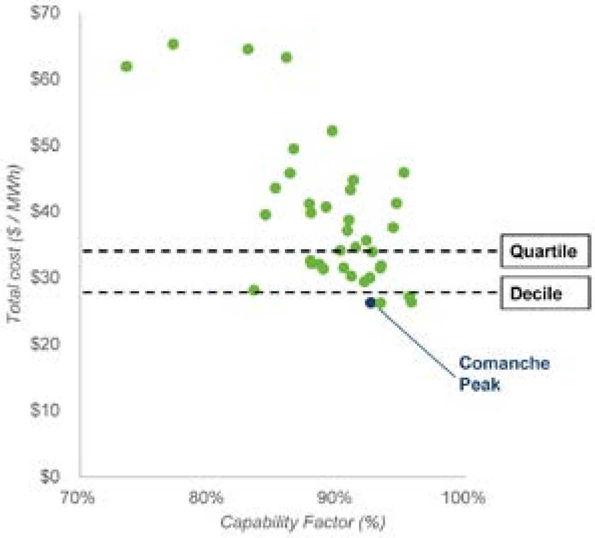
We emphasize most of the focus remains on the seasonally dispatched coal assets, but we see the less nimble peaking steam-fired gas units as also at risk given their long startup times are less ideal to garner scarcity pricing revenues. We emphasize that much of the existing fleet, particularly EFH's larger gas units are indeed for this vintage.

EFH's Comanche Peak Nuclear Plant isn't going anywhere either

Comanche Peak runs at an industry low $26/MWh all-in cost

Comanche Peak, the 2.3GW nuclear plant in mid-Texas built in the early 90s, is one of the lowest cost units in the country according to Luminant disclosures. As shown below, EUCG estimates ~$26/MWh total cost for the Comanche Peak plant – well below ~40 other comparable units but more importantly providing an incremental datapoint suggesting prolonged structural weakness in power prices. 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 (making Commanche among the single lowest cost nuclear plants in the country).

Figure 108: Benchmarking Luminant's Comanche Peak



	Comanche Peak	Decile	Quartile	Median
$/MWh	$26	$28	$31	$37

Source: Texas Competitive Electric Holdings Company July 12 Lender Presentation. 18 month fuel cycle US Nukes, analyzing data from EUCG

Air Quality Regulations Still Coming.. Driving Decisions

The Flip Side: If Anything Might Retire, think Big Brown is a Candidate

Big Brown does not currently have scrubbers.

It's really a question of *when* rather than *if* in our view.. ongoing legal wrangling could take another year however

We see the recent decision to shift towards 100% PRB fuel-sourcing for this plant as indicative of the plant's overall challenges, with the move to this fuel likely incrementally more expensive than its existing lignite sources, but a must as the resources at current mines are exhausted. We note the move to PRB also improves its MATS dispatch profile as well as likely benefits from improved rail delivery terms. While comparably sized, it is the only plant could be targeted by all three new air quality regulations; we emphasize timing on this shut down remains consistent with peers, suggesting a delay into 2017 on a decision point is possible should a stay on the Regional Haze be granted.

Beyond just the meaningful compliance capex contemplated for Big Brown 1&2, Monticello 3 and Martin Lake 1-3 would have modest capex needs for Regional Haze compliance as well. Moreover, across the portfolio coal ash (CCR) compliance capex appears to be the primary driver of incremental environmental capex.

Digging into the legal pathways for the Regional Haze regulations

We emphasize the RH regulations could well evolve in a number of different pathways depending initially on which jurisdiction is adopted for the courts. We note historically the DC Circuit Court has largely upheld agency decisions on RH. All around, we note regulation implementation has proven largely successful in several high-profile examples in recent years including both OK and NM in recent years. Without a capacity market, TX will *not* see coal units converted to gas.

We caution those reading the chart below that high emissions on a trailing basis for SO_2 can be attributed to simply bypassing (not running) control technology; we suspect regulations like Regional Haze would effectively require their use and provide a substantial portion of the delta in compliance. It is really about how stringent the regulations are – and whether existing scrubbers can meet emissions rates below the (0.10lb/MMbtu level). Every increment is increasingly difficult.

[For our Full Latest Report on Texas Air Quality Regs please click here for the full report.]

Figure 109: Coal Power Plants Subject to Regional Haze Substantial Reductions Asked

Facility Name	County	Operator	Coal Type	MW Capacity	Scrubber?	RH Deadline	2014 SO2 Rate (lbs/MMBtu)	2014 NOx Rate (lbs/MMBtu)	Final RH Rule Allowed Rate (lbs/MMBtu)	Reduction - based on rate (%)	Dallas Fort-Worth Exposure
Big Brown	Freestone	EFH	lignite	593	No	5 Years	1.499	0.1313	0.04	97.3	Yes
Big Brown	Freestone	EFH	lignite	593	No	5 Years	1.498	0.1331	0.04	97.3	Yes
Limestone	Limestone	NRG	lignite	893	Old	3 Years	0.472	0.2090	0.08	83.1	No
Limestone	Limestone	NRG	lignite	957	Old	3 Years	0.483	0.2090	0.08	83.4	No
Martin Lake	Rusk	EFH	lignite	793	Old	3 Years	0.739	0.1597	0.12	83.8	Yes
Martin Lake	Rusk	EFH	lignite	793	Old	3 Years	0.696	0.1598	0.12	82.8	Yes
Martin Lake	Rusk	EFH	lignite	793	Old	3 Years	0.726	0.1511	0.11	84.8	Yes
Monticello	Titus	EFH	lignite	593	No	5 Years	0.825	0.1265	0.04	95.2	Yes
Monticello	Titus	EFH	lignite	593	No	5 Years	0.815	0.1183	0.04	95.1	Yes
Monticello	Titus	EFH	lignite	793	Old	3 Years	0.362	0.1565	0.06	93.4	Yes
Sandow	Milam	EFH	lignite	591	Old	3 Years	0.930	0.0621	0.2	78.5	No
Coleto Creek	Goliad	DYN	PRB	600	No	5 Years	0.676	0.1306	0.04	94.1	No
Tolk Station	Lamb	XEL	PRB	568	No	5 Years	0.506	0.1361	0.06	88.1	No
Tolk Station	Lamb	XEL	PRB	568	No	5 Years	0.518	0.1475	0.06	88.4	No
San Miguel*	Atascosa	San M.	lignite	410	*	1 Year	0.519	0.1777	*	*	No

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

Further, NRG remains confident it has found cost effective solutions to ensure the Limestone unit is fully compliant with at least the Regional Haze regulations. While less tangible, we are also increasingly focused on whether further NO_x specific regulations will be imposed on the Dallas/Forth Worth area (beyond the largely SO_2 limitations required for the Regional Haze regulations for ERCOT overall).

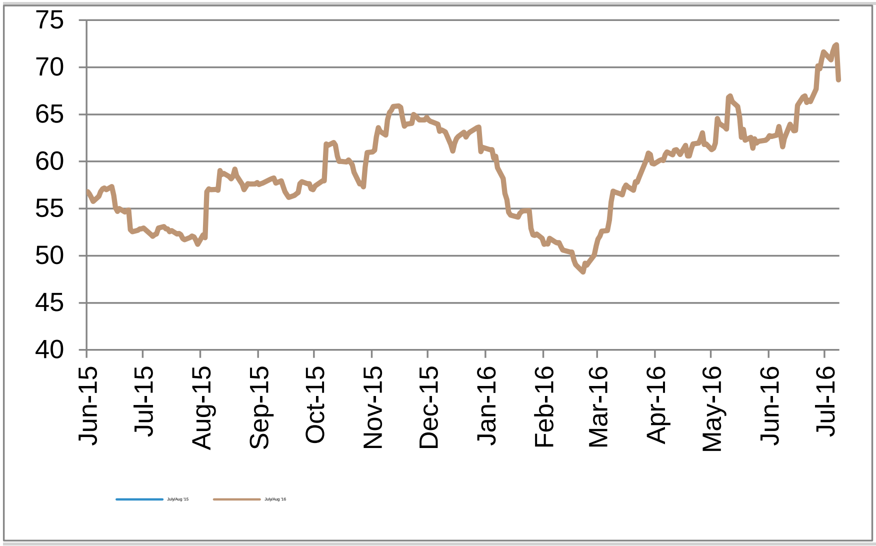
Summer-Time Concerns: Getting a bit Windy of Late?

Be careful of wind dispatch limiting peak price formation during the summer

Among the other growing themes in the market is the penetration of wind. We note recent above-average wind dispatch further calls into question expectations for the total potential wind dispatch into the market at seasonally peak periods, likely weighing on Summer peak price expectations (July/Aug).We emphasize last week wind in Texas claimed a new high water mark for mid-summer dispatch at ~23% of total market share during the hotter ERCOT day – this translates to a roughly ~low 70% capacity factor on the existing wind fleet during a heat wave (despite coincident historic peak expectations for wind during on-peak periods in the ~20% range).

Of late, the summer forwards have recovered to a multi-year high as the split between peak and off-peak has reached new disparities. The question is whether expectations for above-average weather and limited impact from renewables (wind) during peak times will enable this price formation. Overall, recent price trends of late remain quite supportive.

Figure 110: Summer July/Aug 2017 Curve for ERCOT Houston



Source: Platts

Updated Management Projections

We updated consolidated projections from management's most recent projections, in turn applying an adjustment for current power & gas curves; those from mgmt are provided as of 12/13/2015.

Figure 111: TCEH Mini Model

EFH Corp Mini-Model Projections using Mgmt Projections and Updating using MtM Commodities	2014	2015	2016	2017	2018	2019	2020	2021
TCEH Consolidated Adjusted EBITDA (from 2013/	**2,296**	**1,722**	**1,520**	**1,315**	**1,327**	**1,397**	**1,517**	**1,733**
Subtract: TXU Energy (slide 20 actuals)	882	800	784	768	753	738	723	709
Implied Generation (Luminant) EBITDA	**1,414**	**922**	**736**	**547**	**574**	**659**	**794**	**1,024**
Forney Lamar	**167**	**168**	**110**	**157**	**164**	**162**	**160**	**175**
Hedge Value (Disclosed) - 10/15/13 8K	(587)	0	0	0	0	0	0	0
Implied Open EBITDA Generation (Luminant) - includes F+l	**2,168**	**1,090**	**846**	**703**	**739**	**821**	**954**	**1,200**
Implied Open Generation GM	**3,669**	**1,924**	**1,630**	**1,511**	**1,570**	**1,678**	**1,836**	**2,109**
Expected Generation TWh *(Mgmt Projection fron*	**85.4**	**80.3**	**80.0**	**74.4**	**70.9**	**70.9**	**69.3**	**67.3**
ERCOT-North (ATC), as of Dec 31, 2015	33.93	23.78	24.99	27.22	28.93	30.97	32.84	34.76
Houston Shipping Channel Gas as of Dec 31, 2015	4.33	2.57	2.46	2.79	2.91	3.03	3.10	3.18
Implied Heat Rate	*7.84*	*9.25*	*10.16*	*9.76*	*9.94*	*10.22*	*10.59*	*10.93*
Hedged TCEH EBITDA (MtM)	2,296	1,722	1,520	849	906	1,010	1,083	1,145
Implied All-in Fuel, O&M, SG&A Costs ($/MWh)	27	27	26	26	27	27	28	28
Reflecting the Latest Commodity Shifts								
ERCOT-North (ATC) - MtM Improvement/(Declines), $/MWh)			(0.85)	2.76	0.80	(0.98)	(2.85)	(4.77)
Volumes	85.39	80.33	80.03	74.41	70.86	70.87	69.34	67.28
Change in Hedge Value since Dec 31, 2015	-	-	(68)	205	56	(69)	(198)	(321)
Hedged TCEH EBITDA (Mgmt Projections), using latest M	**2,296**	**1,722**	**1,452**	**1,520**	**1,383**	**1,328**	**1,319**	**1,412**

Unlevered FCF Build	2016	2017	2018	2019	2020	2021
EBITDA - MtM	**1,452**	**1,520**	**1,383**	**1,328**	**1,319**	**1,412**
Capex (Inc Nuclear Fuel) (Mgmnt Assumptions)	(384)	(309)	(387)	(335)	(330)	(387)
Working Capital (Mgmnt Assumptions)	(123)	70	8	(16)	(16)	(22)
Taxes (Mgmnt Assumptions)	(24)	(65)	(15)	16	(17)	(115)
Tax Receivable Agreement Pmts (Mgmnt Assumptions)	-	-	(78)	(104)	(90)	(180)
Other (Mgmnt Assumptions)	(209)	(28)	(39)	(41)	(41)	(65)
Unlevered FCF (MtM)	**712**	**1,188**	**872**	**848**	**825**	**643**

Source: Company Filings, UBSe reflects adjustment in commodity viewprice using known Platts power price shifts

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 Integrateds. 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.

Solar sector risks include : 1)Solar panel and other input pricing is subject to ongoing price deflation, which affects economics of downstream projects and margins of upstream producers. 2) Government incentives being added or removed have had a disproportionate effect on demand in the past, and may continue to 3) reliance on power purchase agreements in electricity markets could make future contracts more difficult to sign 4) solar power is directly competing with other traditional generators as well as other renewables like wind, which creates uncertainty as wholesale power markets shift 5)Headline risk and policy risk continue to shift economics in countries as trade policies and changes to other key policies affect solar economics.

Valuation for IPPs are based on sum-of-the-parts analysis.
Valuations for regulated utilities are based on multiples of earnings per share.

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12-Month Rating	Definition	Coverage[1]	IB Services[2]
Buy	FSR is > 6% above the MRA.	47%	32%
Neutral	FSR is between -6% and 6% of the MRA.	38%	25%
Sell	FSR is > 6% below the MRA.	15%	21%
Short-Term Rating	**Definition**	**Coverage[3]**	**IB Services[4]**
Buy	Stock price expected to rise within three months from the time the rating was assigned because of a specific catalyst or event.	<1%	<1%
Sell	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 30 June 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.
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UBS Securities LLC: Julien Dumoulin-Smith; Paul Zimbardo; Jerimiah Booream, CFA.

Company Disclosures

Company Name	Reuters	12-month rating	Short-term rating	Price	Price date
AES Corporation[16]	AES.N	Neutral	N/A	US$12.57	18 Jul 2016
American Electric Power, Inc.[5, 6a, 7, 16]	AEP.N	Buy	N/A	US$69.95	18 Jul 2016
Calpine Corporation[4, 5, 6a, 7, 16]	CPN.N	Buy	N/A	US$14.95	18 Jul 2016
CMS Energy Corporation[16]	CMS.N	Neutral	N/A	US$44.93	18 Jul 2016
Dominion Resources[2, 4, 5, 6a, 6b, 6c, 7, 16]	D.N	Neutral	N/A	US$77.82	18 Jul 2016
Dynegy, Inc.[6a, 7, 16]	DYN.N	Neutral	N/A	US$17.74	18 Jul 2016
Entergy Corp.[16]	ETR.N	Sell	N/A	US$80.38	18 Jul 2016
Eversource Energy[16]	ES.N	Neutral	N/A	US$58.13	18 Jul 2016
Exelon Corp.[6a, 7, 16]	EXC.N	Neutral	N/A	US$36.67	18 Jul 2016
FirstEnergy Corp.[7, 16]	FE.N	Neutral	N/A	US$36.29	18 Jul 2016
NextEra Energy[2, 4, 5, 6a, 6c, 7, 16]	NEE.N	Buy	N/A	US$128.25	18 Jul 2016
NRG Energy Inc.[7, 13, 16]	NRG.N	Sell	N/A	US$15.53	18 Jul 2016
NRG Yield[16]	NYLDa.N	Buy	N/A	US$16.25	18 Jul 2016
Public Service Enterprise Group[16]	PEG.N	Buy	N/A	US$45.90	18 Jul 2016
Talen Energy Corp[4, 5, 6a, 16]	TLN.N	Neutral	N/A	US$13.71	18 Jul 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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