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US Utilities, Power, and Renewables

The 'How Can Utilities Be So Great Again?' Conference Deluge

Equities

Americas

Electric Utilities

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

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

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

Trumping up recent glitzy utility valuations, we reflect on key learnings

While we acknowledge the relatively robust market valuations for the wider sector, investor confidence at our annual conference remained cautiously optimistic with attendance & interest up. We include full company summaries & sector thoughts below

What were the best stories? NEE, PPL among a core selection of reg utes

We heard a number of solid utility stories at the conference. That said, NEE remains clearly near the top of the list with mgmt poised to delineate a full update to its 6-8% EPS target with 1Q results – backing up with projects and an expanded renewable deployment footprint to achieve this recently disclosed higher overall target. Further, we saw PPL as under-appreciated, with the potential for a break-away of its own vs. peers once the 'Brexit' overhang disappears. We also emphasize core utilities such as SCG and AEE remained quite intact as both offered improving risk profiles: nuclear certainty and legislative options in Missouri, respectively, alongside above-average growth prospects. Elsewhere in the sector, we see FSLR as a 'best in class' developer, adding confidence to a beat on 2017e EPS guidance in April at its Analyst Day despite meaningful positive revisions of late. Turning to Power, we see CPN (and even DYN) as the most credible cases for recovery, with the bulk of their above-peer FCF profiles driven by true core gas plants. Lastly, NYLD is our favorite YieldCo structure. We continue to see DUK as a core regulated holding.

What made them de-risk? It's about defensive qualities

Despite earnings headwinds throughout the 4Q reporting season, utilities continued to perform well as interest rates continue to make new lows. Given the clear risk for continued correlation to rates makes the utilities – both domestically and globally – among the most defensively positioned sectors. That said, with 4Q revisions behind us, we are reasonably constructive from a fundamental perspective. We see initial indications into 1Q as suggesting positive revisions are likely with companies delineating yet further ratebase offsets to the immediate negative impacts reported with 4Q already from the recognition of Bonus Depreciation.

Contrasting the sub-sectors: Picking our spots wisely with utilities

Despite this outperformance YTD of the wider utility sector, we're not convinced it's best to hide elsewhere in the space yet. We continue to perceive some caution on the solar and renewable sector as capital market access remains a growing (and spreading) problem. Further, we're largely on the sidelines of IPP and 'diversified' utilities, seeing a lack of clear catalysts through 1H to ensure recovery. Rather, the best argument for IPPs appears tied to the limited FCF generated in markets like Texas without capacity amidst a weak gas tape – and prospects for rationalization under current forward gas curves.

What about the credit risks everywhere? It's a risk but mitigated for utilities

While the sector overall remains dependent on new capital to feed growth prospects, we're not so worried about largely investment-grade issuers across the core utility franchises. While these problems ultimately knocked utilities from their initial defensive positioning in the last down cycle in ~2008, datapoints for the time being suggest capital access remains abundant. More to the point, with limited taxes payable due to a combination of both renewables and bonus depreciation, the sector's risk to capital markets activity would appear meaningfully reduced relative to 2009. Further, with capex actually to see a temporary reprieve in ~2016-17 for much of the sector following a heavy period of spend for much of the earlier portion of the decade, funding needs appear less pressing too. All around, credit risks are not as clear for most equities in contrast to the last cycle.

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Initial Question Bank link: **The 'Making Utilities Great Again' Question Bank List**

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

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

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

Thematic Thoughts

Sector Overview

In Search of (More) Spending: Bonus Depreciation Aftermath

We remain impressed by the relative resilience of the utility sector overall, with earnings growth largely intact across the sector through 4Q. That said, it appears clear that utilities will continue to seek additional spend to offset more of the ratebase growth headwinds created by bonus depreciation. Many stated that, with just weeks to find additional spend to pull forward, they remain confident in providing yet further additional spending projects in the coming months to offset spend. More to the point, bonus depreciation helps make previously contemplated investments all the more 'economic.' We see a general trend towards automated meter reading and wider AMI technology deployment. Examples of companies likely to provide such positive revisions in upcoming quarters including core regulated utilities like PPL and WEC among others. Bottom line, we note a potential positive halo into 1Q with further updates.

Little tax appetite = less interest in renewables.

We note Con Edison was quite clear in its decision to scale back future investments in renewables amidst relatively limited projected tax appetite through at least 2017. While ED's returns including tax credits are a healthy 14% IRR, the economics without such an immediate return via tax credits is substantially reduced. We suspect this could be the trend elsewhere in the sector, even for ratebase projects, which ultimately depend on the utilities' ability to absorb these credits. Meanwhile SO and D appear poised to continue to pursue renewables despite a lack of tax capacity in order to continue to recognize the earnings uplift to backfill any earnings pitfalls holes. SO mgmt. remains confident it can add sizably to prospects for 2017 SO Power earnings (albeit still off the highs of ~$300Mn Net Income guidance in 2016), with new projects including both new contracted CCGTs and incremental wind/solar.

Legislation always a focus: Still true this year.

We emphasize legislative efforts appear under way in a variety of jurisdictions once again in 2016. AEE could continue its latest outperformance as expectations continue to climb around any prospects for a Missouri energy bill this Spring. Following years of attempts to get such a bill passed, a bipartisan effort with Noranda appears the most promising in years. We look for developments in the very near term on POR and prospects for an RPS/Coal divestment bill in Oregon State as soon as this week. Despite reduced investor expectations, we still see prospects for a Michigan deal to be cut this year; we pay attention to Mike Nofs in the Senate Energy Committee – and prospects to reach a compromise bill with other constituents on adding a deal. We see return of customers and new integrated resource planning (IRP) processes as critical elements that should last through any deals.

Among more controversial legislative efforts, we would look for Massachusetts to try once more on a controversial series of solar reforms as well as a wider procurement of renewables. Also potentially controversial, we express continued doubts over potential for a deal in Illinois to address energy matters. This would appear particularly unlikely with the state Budget hanging between the legislature

and the Governor, removing air from the state debate over saving nuclear plants as pushed in the new Illinois legislation.

Midstream Madness: counterparty exposure a growing focus for companies

We emphasize focus for DTE, among other companies, remains on risk relating to midstream producer counterparties, who are off takers from its midstream investments. Despite having clear exposure via its gathering efforts and Millennium pipeline, DTE appears relatively confident on near-term prospects; rather the real question in our view revolves around future growth prospects - and reduced opportunities to benefit from continued expansion. On DTE specifically, the company remains committed to the controversial Nexus project – and has already ordered pipes and hardware to make the project move forward with roughly 2/3rds contracting today. DTE's project exposure appears limited due to the in-the-money nature of deals, while others such as Dominion are less exposed simply due to more of a demand-pull oriented series of contracts. More to the point, D's prospects would appear more limited by the lack of development than meaningful offtake risks across its large system.

Regional Power Thoughts

Beantown Conference Buzzing over Power Prospects

Our annual gathering of the minds in Boston this week provided little obvious relief for the pressures on power. Rather, we are incrementally more bearish on the prospects across all markets except California and New York; we suspect power datapoints could prove more challenging for capacity prints through the spring to drive a recovery in the sector. Further, with IPP credit still in focus, the threat of continued energy defaults could limit any real improvement. That said, valuations remain compelling for a variety of newcomers to 'kick tires' including prospects for private equity among others. Further, we see a variety of secured offerings for select IPPs with capacity (TLN, GenOn, and NYLD) to add to leverage over existing creditors to reduce leverage at a discount to par – adding to equity value.

Expecting a bid? Mgmts continue to look for private deals to save valuations

Managements remain cautious around the thin equity market capitalizations despite meaningful cash flow profiles still, appearing to remain committed to further de-leveraging in an aggressive manner. Despite the relatively depressed equity valuations, mgmts seem to have bought into the merits of de-leveraging, confident the reduced leverage will accrue to the improved equity valuation, particularly if debt can be reduced at a discount to par. In many respects, the prism of capital allocation remains whether independent investments can be done accretively relative to the IRR on paying down debt, rather than the conventional focus on share repurchases.

Securitizing the credit profile: refi's on the come

With credit markets scrambled, secured debt capacity remains the theme du jour. We see TLN as exemplifying this tactical shift towards employing secured lending capacity to both reduce leverage at a discount to par value (we expect tender offers with cash from hydro sales) as well as to subordinate the existing capital structure. This is part of the reason for the relatively wide credit spreads vs. peer IPPs. Further, we see GenOn as similarly positioned with $700 Mn of secured issuance capacity at the corp and $200 Mn at the 'Americas' box. This would appear to lend itself to an intriguing showdown with subordinated creditors. Lastly, YieldCos appear poised to tap latent debt capacity to execute on drop strategies, leveraging secured debt capacity to execute on contemplated deals.

What do we think of power? Cheap, but few catalysts

We remain largely on the sidelines in the near-term. We suspect investors have yet to fully 'internalize' the risks of the upcoming MISO and PJM auction pressures, with upside more 2H oriented, with expected coal retirements (TX) and nuclear retirements (IL) adding a boost to sector via subtraction. We prefer CPN as our favourite IPP play given its largely insulated exposure to both power and credit. Notably, we suspect risks around capital market activity as having been alleviated with the award of Engie to DYN. We also note the staying of the Clean Power Plan (CPP) could well add to a halo emerging to baseload generators such as NRG – all the more presumably boosted by 'normal' realized weather conditions. With valuations well below the previous 2009 lows on an EV/EBITDA basis, the wider question among power investors is how to rationalize where shares could 'bottom' and with what 'methodology'?

Don't Keep Blaming Bonus Depreciation for Power's Problems!

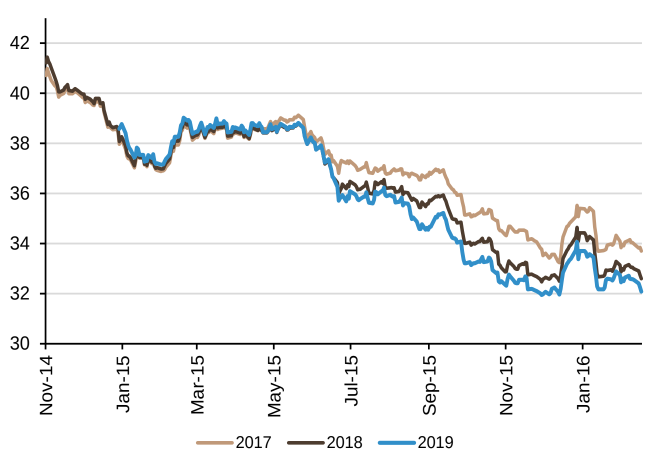
While it has become almost common place for investors to blame the lower clearing price of the New England auction outcome on bonus depreciation, we emphasize it is a private entity, Invenergy, that drove the clearing price with a greenfield plant. We emphasize many private entities typically do not have straight forward tax capacity – and likely did not bid to take advantage of the wider tax backdrop. While PSEG may indeed have cleared its brownfield uprate on account of this benefit, the ultimate auction outcome remains more complex than simply chalking up this tax differential.

PJM: Expect a down market – but how much new build?

While investors and companies largely agree that this year will be a 'down' year for the upcoming capacity auction, the wider discrepancy in expectations remains just how new capacity will continue to clear YoY. We're biased to continue to see at least a couple new CCGTs clear (beyond the new Dominion regulated CCGT contemplated). We also emphasize plants that are already under construction but may not have cleared in last year's auctions due to the sudden introduction of tighter bidder standards due to CP rules that may yet clear for the first time. The range on expectations appears between 0-5GW of new supply. All around, we see downside to our $140/MW-day estimate; we perceive Street expectations as being largely around the $140-150/MW-day level.

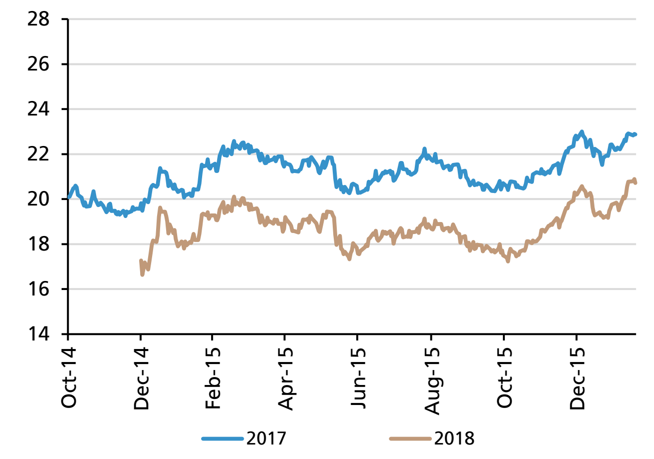
We also note that estimates for a subsequent recovery are likely a bit too robust – with Demand Response remaining more resilient than many expect as requirements are scaled to 100%. ENOC expects to maintain a largely flat revenue profile through the transition to full CP requirements in PJM, illustrating its confidence that the shift to annual profile will seemingly preserve the vast majority of MWs (with a correspondingly higher price by selling into the CP auction vs. the base auction today for its ~3GW of capacity).

Figure 1: PJM West ATC power prices ($/MWh)



Source: Platts

Figure 2: PJM West Spark Spread @7.2 Heat Rate ($/MWh)



Source: Platts

New England prospects look lower too

Following a weak showing in the capacity market this year down to $7.03/kW-mo, we remain concerned of further pressure on prices into the next year, down a modest bit. Factors poised to put pressure YoY include the introduction of a new

demand curve shape (estimated at almost ~$2/kW-mo by ESAI consultants). Further, we suspect a continued slow addition of renewables resulting from the ongoing RFP (up to 200 MWs are eligible without MOPR application) as well as some pressure on load projections from continued distributed solar penetration. All around, we see risk to the ~$5.50/kW-mo range for the FCA11 (2020/2021) auction next February. Lastly, with Invenergy willing to clear at $7.03/kW-mo, we are worried of further new capacity lurking (*albeit still don't expect more next year – but rather acknowledge a clear latent risk weighing on any upside potential for now)*. While several have pinned the blame on bonus depreciation, we do not believe this is the case given the low price bid by this private entity into the auction (without obvious tax appetite of its own).

That said, with the Bridgeport coal unit set to retire in the subsequent year (2021/2022), we see the possibility for some firming. We also note the ES' spin of the Merrimack coal plant out of regulated cost-of-service treatment into a position as a merchant IPP – and would be the last coal plant in the region. While going forward costs would appear to support the plant, this would be the 'next' marginal plant after Bridgeport in our view.

Mass legislation more likely to be successful?

We continue to expect legislation to (finally) be successful this year in MA following several years of failed efforts. We suspect the combination of a committed administration, alongside a wider effort to not let solar caps limit the prospects for growth in the state will force a compromise position.

We're not too worried about the prospects for solar.

With many solar advocates quite concerned on what the failure of solar legislation in the state means for the nascent industry in the state – we just don't believe a meaningful pullback is upon us, particularly for the resi market. While a reduction to NEM is possible on the margin, we suspect this will remain a (small) part of the overall ambitious renewable program.

Question for ES remains just how much procurement happens?

Our outstanding question around the pending procurements arising out of the deal remains just how much is ultimately pursued under the construct. While the initial proposals call for 18TWH (~6GWs of wind by our math, ~2GW around-the-clock power), almost impossibly large to imagine, even a compromise position could well drive outsized procurement for years – negatively impacting the IPP market, but also making it among the single largest events in US renewables ever. More to the point, the question remains whether the cycle would be gradual or assigned all at once.

'De-Carbonization' of the Energy Economy: ***Coming*** **to New England**

Akin to California the success in New England on reducing carbon emissions with a substantial reduction in coal in recent years is also driving an expanded view on how to address emissions from other sectors of the economy including both industrial customers as well as principally transportation which makes up the vast majority of the regions overall emissions. We wouldn't rule out ES pursuing peers out West in evaluating Electric Vehicle (EV) solutions; the question is how exactly ES could participate in such an opportunity.

Northern Pass: Making the Transmission Economics Work

We remain confident on the underlying project economics despite the collapse in regional gas (and in turn power prices), seeing HQ as seemingly desiring the optionality to sell into the market. We emphasize the plan does not appear to contemplate significant potential for capacity to be cleared under the exemption. Further, with HQ not necessarily having excess firm capacity to sell into the region anyways, this does not appear the focal point of the project. Rather, it's about arbitraging out the shifts in energy prices across the regions.

Project to be mitigated but expect some to clear anyways.

While there has been substantial attention paid to the effects of the project on the capacity and energy markets, we emphasize the reality is that the MWs cleared will be predominantly leveraging the 200MWs per annum of 'exempted' renewable capacity. We suspect the carve-out exemption of ~200 MWs of new capacity will be fully utilized with this project (we understand the trailing 3-years of exemption can be used, effectively allowing for ~500 MWs of capacity to be cleared from HQ without applying a MOPR).

Setting an initial expectation for next year.

As a broad rule of thumb we expect prices to sink to near the auction floor price at $5.50/kW-mo tied to limited incremental retirements as well as new curves, and potential for at least one of the new transmission/large renwable projects from the ongoing RFP this year to push down expectations. We expect continued annual procurements from the RFPs (likely passed in MA) to continue to keep a lid on this compensation through the near term. Bottom line, we expect continued meaningful 'turnover' in the underlying fuel mix as coal and legacy gas assets as well as eventually the region's nuclear plants are pushed out.

Offshore wind back on the map?

Among the other burgeoning potential trends in the sector is the potential for offshore wind to re-emerge as a competitive option vs. on-shore conventional approaches. We suspect New England could well revisit the subject alongside other regions as larger systems with 7-10MWs enable these systems to have more scale; the Cape Wind project was contemplated with 3MW turbines for instance. Costs of north of $200/MWh appear to be declining materially.

Notably, the continental shelf off the US enables for relatively shallow waters to be found reasonably far off the coast, outside of coastal views.

This contrasts against the $70/MWh for typical wind systems installed onshore, typically in the windier corridors of Maine. The key question in the ongoing RFP is whether transmission projects from adjacent regions will end up being competitive vs. the high cost of making projects deliverable into the region. Seeing the Southern New England States as the primary drivers of procurement, we wouldn't be surprised to see solutions that have more of a Southernly orientation (benefits besides just the Renew Energy Credits, RECs).

The New England Nukes are at Risk – another wildcard

Looking holistically at the New England region, among the biggest wild card remains not just the retirement of the last coal burning plants, but also the prospects for the continued viability of both Millstone and Seabrook (1.1GW single unit site) under a depressed gas outlook. We expect each of these units to

respectively be retired eventually under continued pressures from gas in the 2020's – or when earnings turn negative for D and NEE, respectively, the owners of the plants. The question remains whether the states will step-up to save each of them given the carbon impacts; we note 2015 saw increases in carbon emissions in the regions despite lower gas prices as the Vermont Nuclear Unit stepped off.

Expecting the Pilgrim Unit to Retire Early

Given the potential capex retrofits required as a function of safety-driven retrofits, we understand the Pilgrim unit could well retire in an accelerated manner during its 2017 outage, rather than waiting until May 2019, when its current capacity obligation rolls off. While buying the obligation back in the incremental auctions would appear expensive, the incremental capex incurred could alternatively prove more expensive. We see this as a negative potential increment vs. our current estimates embedded in our ETR model.

Divestment (of remaining NH generation): Limited risk to ES

Despite seemingly limited value remaining for the Merrimack plant in NH (after the installation of scrubbers) in a possible divestment, ES would remain whole on revenues after sale proceeds. That said, we don't necessarily see an immediate retirement of the Merrimack plant under the status quo outlook with ES ownership. We look towards any ownership decision arising from a new owner. There remains further risk to the Schiller coal project, at least the two remaining coal burners (each are 50 MWs); the third is a wood burning boiler, likely sticking it out. The balance of the ES portfolio likely 'makes it' upon exit.

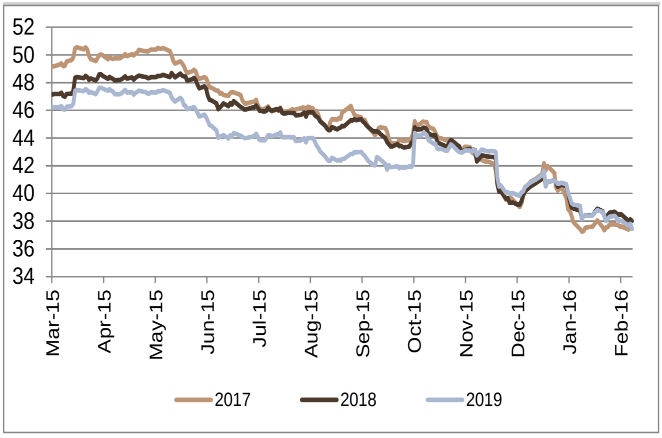
Pay for Performance: Starting to Focus on Steam-Fired units

Among the wider structural questions remains whether slower-ramping steam-based plants will begin to be retired once the Pay for Performance (PFP) scheme is finally adopted. We note the region is clear in its willingness to let plants retire if unable to meet more stringent operating factors. Among key plants to watch in our view are Canal Units 1&2. Timing on PFP-related retirements could still be a few years out and only once such obligations are triggered. Further, with NRG managing a wider portfolio of risks, this remains a key focal point.

The question is whether plants will be allowed to retire?

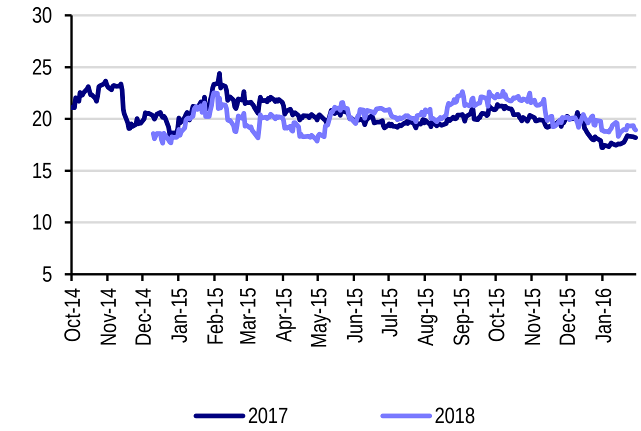
Amidst the latest ISO-NE proposal to more closely scrutinize (and potentially block) retirements of units belonging to larger IPP fleets, the question is if the added 'costs' (and risks) of complying with the PFP rules will be reflected in bids. This could act as a limiting factor to further retirements.

Figure 3: Mass Hub ATC power prices ($/MWh)



Source: Platts

Figure 4: Mass Hub Spark Spread @7.2 Heat Rate ($/MWh)



Source: Platts

Spark spreads would appear to put some modest downward pressures on power.

Among the key debates among many power investors is whether continued gas basis pressure on the New England market will put pressure on spark spreads. While it would appear to present some modest pressures, the real risk remains to those with existing entrenched positions and/or poorly positioned gas procurement points across the Northern and Eastern extremities of the New England footprint. We largely expect spark spreads to remain backwardated through the medium term, particularly with the threat of large-scale hydro still looming in the back (ESAI consultants estimate the impact of the proposed HQ interconnection as being ~$2-2.50/MWh). We continue to see the New England market overall as 'peaking out', albeit at a relatively high rate of compensation for both capacity and energy.

MISO remains the risk, as Zone 4 no longer clearly clearing separately.

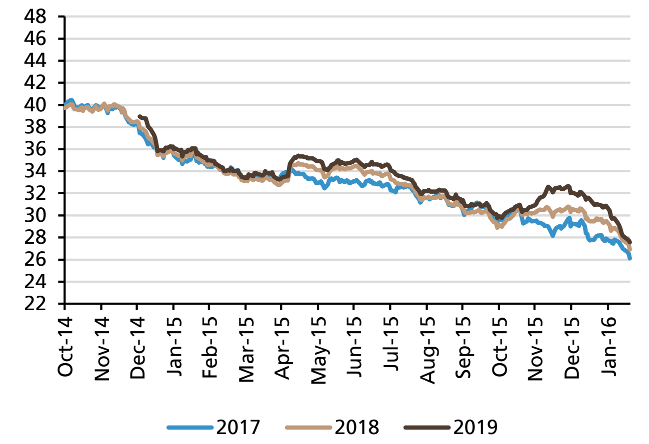
As if there were not enough negative catalysts ahead for the power sector, we see the next Capacity Auction print in early April for the MISO market as among the next likely more negatively biased datapoints. We see prices as likely clearing in a range of $25-100/MW-day, down from the ~$150/MW-day previously expected as the effect of the latest FERC order on bidding rules takes hold. We note the primary reason for this is not just the change in bidding rules imposed on the market, but a meaningful reduction in the required Local Clearing Requirement (LCR) for the Zone 4 region (this shift is due to the large quantity of MWs exported to other regions/PJM, enabling greater transmission latitude from other adjacent areas in MISO into Zone 4 under the new methodology). We emphasize EXC's Clinton nuclear plant is likely to continue to clear the auction, seeing a retirement only possible as soon as next Spring, 2017. We suspect MISO could well 'bottom' with this latest capacity auction – seeing a real potential for both further DYN coal plant retirements as well as finalization of plans to retire the EXC Clinton plant resulting out of this process.

A wider (and more relevant question for DYN) remains where bilateral pricing trends with a weaker RA auction datapoint, as much of DYN's capacity is actually hedged in these less transparent markets.

How long can assets hang on? Texas remains the test case.

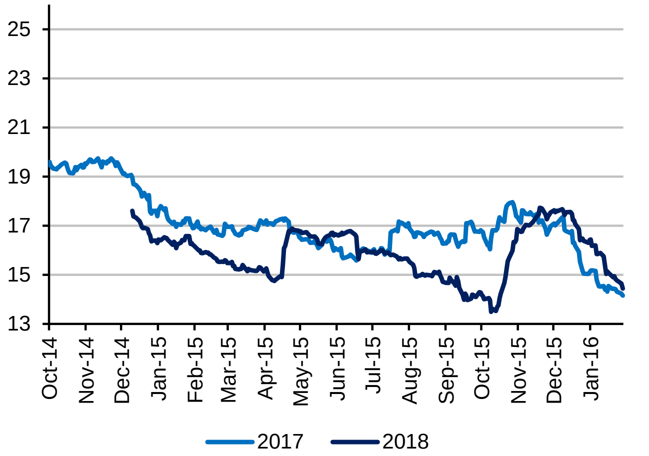
We continue to look to Texas as the test case of any eventual recovery in the power markets, with >30% of assets losing FCF actively in the state. We look for not just EFH to lose coal capacity due to new coal regulations, but also DYN's recently acquired Coletto Creek (pending acquisition). NRG remains adamant in keeping its units open through any such cycle, seeing its coal portfolio as advantaged (this is not readily apparent—but mgmt. remains confident it can meet Regional Haze regulations without any substantial capex to retool the scrubbers around any such rules). We reiterate ERCOT as our favorite market, seeing as not just coal plants as at risk, but also nuclear and gas plants as needing to recover their fixed costs through sparks as well. We see particularly steam-based technologies as insufficiently nimble to 'clip' adequate peaks to make economics 'work' to recoup fixed costs.

Figure 5: ERCOT Houston ATC power prices ($/MWh) ATC prices ($/MWH)



Source: Platts

Figure 6: ERCOT Houston Spark Spread @7.2 Heat Rate ($/MWh)



Source: Platts

California Power has some modest surprises

While hydrology in the states continued to normalize, we emphasize a few other factors could help keep this market dynamic. Most importantly, the resolution of PG&E's pending GT&S gas for rates on its pipeline network is of particular interest. We note increases on customers *behind* the gas LDC could see rates increase by as much ~$1/MMbtu; this would particularly impact DYN's Moss Landing CCGT ahead of a potential sale later this year. We suspect this could drive a modest positive impact to spark spreads later this year. We note this would be a positive for Calpine's more 'interior' portfolio of gas plants – which largely source their gas directly off the gas pipeline network into the state rather than via PG&E/LDCs. Further, CPN mgmt. cited potentials for changes in California export 'wheeling' charges to send electricity *out* of the state on particularly intermittent days, which can be as high as $13/MWh.

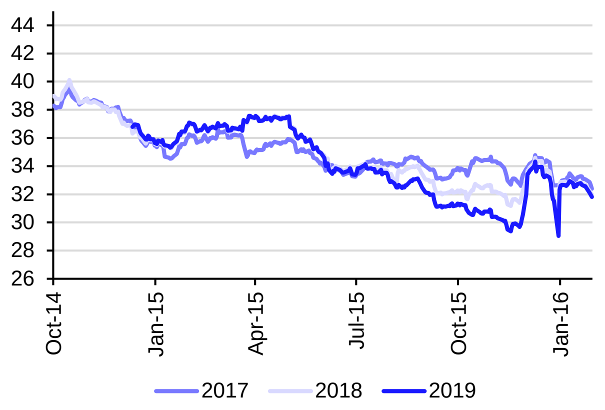
That said, this is all in spite of a continued meaningful influx of new renewables into the state suggesting a more structural pressure on spark spreads.

New York: More Retirements Please?

We see this market as among the more promising regions, looking at not just the realization of contemplated coal retirements from NRG, but also limited economics

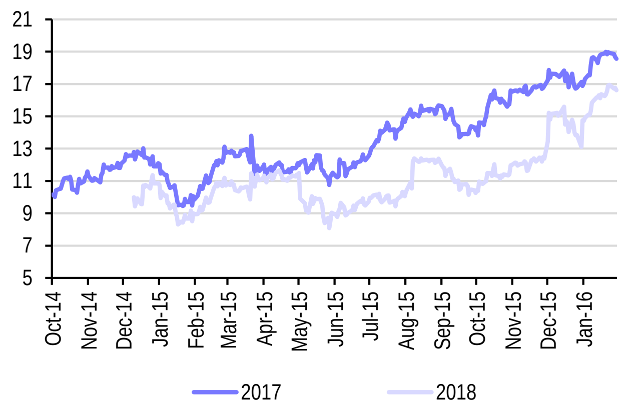
for other remaining plants (Somerset and Cayuga). We suspect the market here could well be 'coal free' in the near term alongside New England. On the nuclear side we see Ginna as likely to be saved by a coal deal, while prospects for ETR's Fitzpatrick unit likely hang in the balance around any deal to save Indian Point for at least a limited period of time too. That said, our downstate outlook could remain under pressure given shifts in parameters. The Lower Hudson Valley (LHV) market remains likely to clear with the Rest of State (RoS) market over time as new transmission enters service.

Figure 7: NY Zone A ATC power prices ($/MWH)



Source: Platts

Figure 8: NY Zone A Spark Spread @7.2 Heat Rate ($/MWH)



Source: Platts

Renewables Review

Trumping capital markets concerns, solar markets focus on utility-growth

At our latest industry conference, mgmt teams continued to articulate constructive views on the outlook for solar despite the concerns of financing raised by some. We sense a clear bifurcation still between the resi and utility-scale markets, with those most well capitalized in the solar industry (FSLR, SPWR) positioned to meaningfully take market share from those on the sidelines. We think constructive datapoints could come out of the FSLR April 5th Analyst Day and shares could react positively as a result. On the YieldCo side, NYLD remains our favourite, with NRG mgmt reiterating its commitment to growth. We emphasize newly appointed CEO Mauricio Gutierrez appears poised to turn its loss-making resi solar efforts into the black within months of appointment via a partnership model. Mgmt remains structurally committed to the entity and sector, NYLD should outperform the wider sector and parent sponsor, NRG, in our view.

Doubts continue to swirl on residential solar prospects

Among the key themes at the conference was the contrasting prospects for utility-scale developers (NEE, FSLR, SPWR, etc) vs. smaller-scale efforts by the likes of SCTY and others. We suspect the Street is increasingly keyed in for reductions in MW guidance for SCTY (and disappointing results for yet another Qtr). Success on sell-down of assets and updates on tax equity and ABS prospects remains key to improving beyond any quarterly or 2016 outlook on execution. Investors continue to look for a bright spot with mgmt at RUN which is poised to provide a long-awaited update on its prospects on March 10th.

How much Solar will be deployed? Improvement is a volume focus.

Among the critical questions asked is just how much incremental volume can be deployed at FSLR as the company prepares for an April 5th Analyst Day in New York. We continue to see the story for utility-scale as primarily a volume story – rather than margin – both would appear on the table as expectations on EPS for the company into 2018 continue to rise with the stock. The question remains whether it will be able to post north of $4 in EPS in 2018 as it discusses the next 'bull market' cycle in 2018. The question for FSLR will be just how similar its prospects are to SPWR, which has promised a doubling of revenue and EBITDA by 2020. Recall FSLR continues to have mothballed capacity (8 lines or roughly ~900MW by our estimates), providing a low-capex source of additional MWs; we suspect this could be accomplished through deployment of existing cash on the balance sheet. <u>While still pricey, we think FSLR could provide a bullish view on prospects at its April 5 Analyst Day.</u>

Swapping for Direct Contracting: Growing prospects for C&I deals

We look for the C&I market to continue to prove a key source of incremental tax equity liquidity for both utility-scale and residential sectors alike – as well as an important source of hedges to support continued renewable investments. We note the latest SCTY tax equity deal was sourced from a corporate counterparty, and wouldn't doubt continued success in sourcing such tax prospects. Following disclosures in recent months that upwards of ~50% of wind deployed last year was driven by direct commercial and industrial contracting, prospects continue to accelerate with multiple companies noting interest for opportunities including the likes of Dominion among other utilities. We emphasize this appears to have been primarily a wind-play thus far but we see solar as a burgeoning subject.

Private vs. Public: Power & Solar

- The discrepancy between the private markets and public remains clear with multiple companies stating they were receiving inquiries from private entities to own shares rather than invest in private assets elsewhere in the sector. We don't discount the potential for large positions to be taken by strategic investors in YieldCos, solar companies, and especially power. We suspect the endorsement from ECP's 15% stake in DYN is just as important as the acquisition of the Engie power portfolio last week in pushing up shares. Mgmts from YieldCos noted interest from private investors in investing in their shares --- rather than investing in private assets.

Net Metering remains the focus: Utilities on the up?

- There seems to be a clear perception that utilities are 'winning' the question on net metering more broadly. While NEM reform appears real and active across a wide variety of states, we would expect to see both grandfathering left intact – as should be the case in AZ despite any future reforms. Further we expect an extension in Mass to the NEM program, albeit potentially with a 'hole' for a period of time; lastly, while New York is evaluating NEM reform of its own, compensation is likely to remain generous with a substantial 'societal benefit' adjustment to ensure robust market development.

Arizona: Seeing Demand Rates Shift

- PNW appears poised to pursue a more demand-centric charge, seemingly dropping its current solar-specific charge. The proposal would appear to ask for 30-40% of the bill to be based on peak monthly demand, as proposed by the Staff. We suspect any adjustments in the rate structure will still permit *some* amount of solar to materialize – albeit at a muted pace.

Buyer's market…but who will pounce on the opportunity?

- Multiple players highlighted that it is a buyer's market currently, for wind and solar assets and portfolios, and nearly all segments of the asset segments (resi/utility/C&I). The key here is that there are several distressed companies that need liquidity, and have significant pipelines and operating assets that are potentially available for purchase.

- Many participants were discussing the various resi solar portfolios seemingly up for grabs. On the utility-scale, there are major players in distressed positions that could potentially be looking to offload assets or pipelines in return for near-term liquidity. Additionally, many European wind players with operating assets and pipelines in the US have cooled given the devaluation of the Euro.

The key question is who will be the buyers of the assets, and at what yields/IRRs?

- NEE specifically stated that they see the opportunity to take advantage of the market situation, with YieldCos and SUNE on the sidelines, which were largely the most aggressive players roughly a year back. Separately, FSLR and SPWR discussed the opportunities given their liquidity positions.

- While levered IRRs on projects were running in the 5-6% range during the height of competition, players expect IRRs to return to the high single digits, and potentially even low double digits in some cases.

Who will buy the resi assets?

- Given the timing of the conference, many attendees and industry participants were discussing the potential resi asset sales that are being vetted in the boardrooms of major players. The key question is, (as there has never been a ~100MW bucket purchase in the space) who will purchase the assets for the first time?

- Pension funds, utilities and private equity firms could potentially get involved. It remains to be seen which type of entity will be looking to enter the 'unknown', but we think that if PE were to get involved, the resi counterparty will likely need to be distressed given the return requirements for the PE players.

Where is the competition in utility scale?

- On the development side, NEE stated that they have seen many competitors exit the market, leaving only a handful of players capable of taking advantage and inheriting the remaining market share. On the wind side, a sizable amount of large European developers have exited the US, leaving NEE and a handful of small developers left. For utility-scale solar, NEE, FSLR, and SPWR are looking to gain share in the key markets, and all three are citing the Southeast as the biggest opportunity in the market currently.

Fundamentals strong for renewables

- All participating corporate and industry players noted that the fundamentals for renewables in the US are potentially as strong as they have ever been, with the CPP stay the only overhang, but with that impacting the market in the 2020 timeframe. It is clear that projects will continue to be brought to the market, whether it be by private or public players.

Private vs public…which has it right?

- With the high-profile burst of the YieldCo bubble, the key question for HASI and other players was which of the markets – public or private – have a better understanding of the space…

- For 18 months before the downturn, HASI noted that they saw better value in the debt than the equity, with better return prospects on the debt side, and higher risk in the equity. The leading indicators that the public markets were a bit inflated were the IRRs that the players were paying for assets—in the 5-6% range, or essentially break even in many cases. Having said that, given where the debt and equity markets are currently, HASI doesn't believe that the private players have a better grasp of the sector.

What's the strategy for yieldcos and their sponsors? Integration?

- Relative to the YieldCo market, we met with PEGI, HASI, ABY, and on a less direct level FSLR/SPWR (CAFD), NRG (NYLD), and NEE (NEP), to try and gauge the direction that the YieldCo market will take:

- Given ABY's intention to distance itself from Abengoa the CEO indicated they are keen to find a new partner(s).

- HASI continues to support the sponsor-*less* model, with all development done inside a single entity. Mgmt believes that this is the most streamlined option, and expects the market to evolve toward this model. HASI pointed to Brookfield Renewable Energy as another example of this, and a company that has largely been able to avoid the YieldCo downturn.

- As for PEGI, they have made their intentions to acquire the DevCo clear, with the plan not viable given the current status of the YieldCo. Having said that, the CFO noted that they are entertaining preliminary integration discussions with Pattern Development.

Payout ratios…what do these mean when YieldCos trade on DCF?

- ABY mgmt hypothesized that the YieldCo market would be in a stronger position if YieldCos shifted payout ratios from 80-90% into the 40-60% range, in order to give the companies more flexibility.

- The key here is to what extent the share prices would take a hit if companies pursued this approach, with YieldCos no longer trading on yield, and largely on the DCF of the operating portfolios. Industry participants stated that the vehicles have heavy retail interest, which would react negatively to dividend cuts, but that the institutional players would likely have less negative reactions.

Commercial still an untapped market…how does it take off?

- While FSLR, EIX, and SPWR are focused on obtaining significant share in the commercial space, GTM Research noted that the market hasn't grown in the past three years—pointing more to the lack of uniform credit standards, along with significant fragmentation. SPWR and EIX are entering the market through organic development efforts along with strategic acquisitions, but while these should allow the companies to take greater share, the key question is whether the market as a whole is mature enough to start growing at a similar rate to utility and resi.

- Many players are pointing to the PACE program, which is gaining popularity across the US, and has the potential to add more uniformity from a diligence and financing perspective. It remains to be seen if PACE has the potential to drive the market to higher levels of growth.

Alliant Energy (Unrated)

Top Three Takeaways:

(1) *Alliant was one of the utilities that was able to accelerate* <u>*incremental*</u> *projects due to the extension of bonus depreciation and this $260Mn 2016-2019E additional spending is expected to offset the impact of bonus depreciation from. LNT still expects to need equity for its Riverside project but any dilution is already contemplated in its 5-7% EPS target.*

(2) *With capacity factors in the 35-50% range and sites under its control, it is a question of when not if Alliant will add more wind. Recent pricing for wind has been ~$0.03/kwh and going forward management intends to strike a balance between PPAs and utility ownership to provide more diversity. In contrast originally Alliant only pursued PPAs. While Alliant would like to own more wind it is focused on bill inflation in Iowa where it expects to file for a rate case in April 2017 to recover spending on Marshalltown.*

(3) *Alliant is still evaluating its options following the ITC Holdings/Fortis transaction but has had dialog with ITC since the deal. Prior to the transaction (October 2015) Alliant filed an informal challenge against ITC regarding bonus depreciation as transmission rates continue to create pressure on Alliant customer rates, particularly the industrial users. If Alliant decides to intervene in the merger the first question would be at which jurisdiction.*

Moving the pieces of Riverside: In February Alliant offered local co-ops an option for 55MW of capacity in its Riverside project but this is accounted for by the plant having ~50MW more capacity than originally contemplated for the same $700Mn cost. The co-ops have to make their election by September 2016 and in return for the option the parties agreed to a four-year wholesale contract extension to 2026 at the same 10.9% ROE. Management is continuing to monitor the resource plans for MGE and WEC as they also have the potential to add ownership in Riverside (50MW and 200MW respectively) but those possibilities are not yet reflected in the capex plan as the decisions would be after construction is completed. If WEC acquires capacity then LNT can purchase 200MW of the next WEC CCGT created before 2030 so the impact on ratebase largely offset although there could be lag. The Wisconsin PSC is expected to decide on the Riverside Expansion by 2Q16 (Docket 6680 CE 176).

Reduced sales expectation a driver of lower 2016E earnings expectations: Alliant now expects sales growth to be +1% overall versus +2% in Wisconsin and +1% in Iowa. Management is working with the Wisconsin government officials to see how the company and the state can work together to promote further economic development. Despite the reduced sales target this year, management stated that it is comfortable with its long-term earnings guidance.

Ameren Energy

Top Three Takeaways:

(1) *Management is keeping its cards close to the vest on potential MO legislation but with more parties seemingly more aligned than ever, the stage appears to be set well. Importantly Ameren reports that other large industrial users are supportive of Noranda, as offering a lower electric rate to NOR could help to mitigate a potential rate increase for the rest of the industrials in a scenario without Noranda.*

(2) *After numerous examples of challenging energy legislation across the US lately, we would recommend that investors exercise caution on forecasting whether legislation occurs or not. While there do not appear to be overarching issues that would monopolize the legislature's time in Missouri currently, the path to new legislation has rarely been smooth as we have seen from following other states.*

(3) *Investors have focused on the elements of the new 5-8% 2016 Adj.-2020E EPS CAGR and assumptions around treasury rate improvement at IL and how management can achieve the high-end of the range but even at the midpoint of the range the earnings profile is above-average (as is the dividend yield).*

Industrials look to mitigate their losses: Noranda continues to advocate a significant reduction in its electric rate to achieve a 'competitive' energy rate that will allow the Missouri sites to be competitive if the global market for aluminum recovers. Electricity is approximately one-third of the cost of aluminum based on AEE management and the combination of a lower electricity rate and interest relief from the bankruptcy could help to keep some production on-line. Noranda's current rate is set at: Summer (June-Sept) rates of $45.78/MWh and non-Summer (October-May) rates of $31.11/MWh. Ameren noted that other industrial customers have been supportive of Noranda's position based on the argument that without Noranda, Ameren would simply sell its output in the market via off-system sales and the delta between the ~$27/MWh ATC Indy Hub price (pre-basis discount) would have to be spread across industrials.

Parties are more aligned than ever but this does not guarantee success: With all of the public utilities continuing to advocate for legislative reforms plus Noranda and other industrials, the landscape appears more favorable for the parties to engage in constructive conversations than it has been in the past. Following prolonged legislative efforts in Michigan and Illinois recently, <u>we caution investors about being too optimistic about the prospects for legislation actually being approved in Missouri</u>, particularly after previous efforts in the state that did not ultimately cross the finish line. Ameren recommends watching the Senate process more closely for faster developments but also sees strong leadership in the House's Energy and Environment Committee where a bill could originate. If the process moves quickly then more comprehensive versions of the bills could be filed in the next few weeks (Senate Bill 1028 and House Bill 2495)

We emphasize AEE could continue its latest outperformance as expectations continue to climb around any prospects for a Missouri energy bill this Spring. Following years of attempts to get such a bill passed, a bipartisan effort with Noranda appears the most promising in years.

Attempting to avoid expectations creep: Management is logically hesitant to address how potential legislative reforms could impact ratebase growth or the long-term earnings per share CAGR given the wide degree of permutations that legislation could take, if successful at all. As of YE15, Missouri rate base was $7.1Bn versus $2.4Bn for Illinois Electric ratebase so we believe it could be challenging for Ameren to grow the larger MO base in line with the 2015A-2020E

6% target for IL Electric but it is apparent that management would have additional capital deployment opportunities above its current MO plan if the regulatory construct in Missouri improves. While management does not anticipate requiring any equity issuances today based on its current plan, in a scenario where Missouri or another segment provides enough value-enhancing growth that equity is required, then management would re-evaluate its position.

Atlantica Yield

The majority of the ABY conversation surrounded the possibility of an Abengoa bankruptcy filing, and ABY's plan to separate itself from the parent. One of the issues in an Abengoa filing would be how the projects would be maintained, with Abengoa taking care of the O&M currently. Unless Abengoa gets liquidated, ABY stated that they would still service the projects; however, in a liquidation scenario, ABY would likely hire the O&M employees to handle the situation. They would expect this to be a net neutral on the business. ABY has created a $20-35Mn reserve account which will cover risks that could impact the assets, which could not be covered by Abengoa. The company will use this for any required repairs or maintenance t that the sponsor cannot support, in order to keep the assets operating at full strength.

As for the ROFO list, mgmt stated that equity holders want the ROFO to remain with Abengoa, which would occur if liquidation does not take place. Having said that, ABY conceded that it's likely ROFO assets could get sold to private equity at a discount in order to provide Abengoa with capital.

ABY does not want to bring development in-house in the short term, but notes that this could be an option further down the road, as there is a quality team of developers at Abengoa that could potentially be hired under the ABY brand.

ABY would need to find an alternative solution to the current FX hedging in the case of an Abengoa filing, as ABY would need to take a shorter-term hedge with a bank if Abengoa cannot cover this.

As for the dividend, ABY recently pushed this back as they need to take care of some risks before paying it. They expect the dividend to be in the 80-90% range. ABY mgmt hypothesized that the YieldCo market would be in a stronger position if YieldCos shifted payout ratios from 80-90% into the 40-60% range, in order to give the companies more flexibility. The key here is to what extent the share prices would take a hit if companies pursued this approach, with YieldCos no longer trading on yield, and largely on the DCF of the operating portfolios. Industry participants stated that the vehicles have heavy retail interest, which would react negatively to dividend cuts, but that the institutional players would likely have less negative reactions.

Black Hills Corporation (Unrated)

Seeking out more utility growth

On the heels of its successful acquisition of SourceGas, management has set its sights on ultimately growing the utility platform to roughly double the current 1.2M customers over time through a combination of organic investment and M&A. Management emphasizes that nothing is imminent and there is no specific time frame for this goal; it could be over the next 10 years or less should the opportunity present itself. The company expects to benefit from its previous experience with the Aquila acquisition, with many senior personnel from that merger now expert at corporate integration and synergy generation. BKH's preliminary guidance for 2017 is $3.50 vs prior consensus of $3.24. Although the preliminary range is a wide $0.30, it includes robust synergy generation within it, including the consolidation of corporate level headquarters and the reduction of redundant office facilities and call centers. Furthermore, no ratecases for SourceGas utilities are expected to be needed for ~5 years, with some capital spending there handled through riders.

Cost of Service gas program coming together

Management remains confident that its plan to place both producing and development properties into ratebase will be approved. The company is currently in the process of educating regulators on the advantages of reduced pricing volatility given the ability to drill at the $3.00-$3.50 level and lock that cost in for 25 years. Nebraska and Iowa are the two biggest opportunities, with a settled outcome preferred. BKH expects to be in a position to disclose more by the end of 3Q, with the Analyst Day set for October.

Calpine Corporation

We prefer CPN as our favorite IPP play given its largely insulated exposure to both power and credit.

Top Three Takeaways:

(1) *Despite characterizing itself as "comfortable" with its leverage on the 4Q call, management reiterated that reducing debt is a priority when it considers capital allocation. Mgmt appears to regret not being more forceful in articulating this strategic objective on the call. We see this as a positive update to address investor concerns.*

(2) *Based on recent power transactions/datapoints management characterized itself as pleased with the asset acquisitions it has made lately. CPN continues to be open to asset sales as it has in the past if other parties value the assets at a higher level than CPN does based on its market views.*

(3) *Calpine continues to believe that the next ISO-NE auction should clear close to ~$9/kw-month if new resources are needed. Based on its analysis CPN estimates the auction would have cleared closer to $9/kW if not for the recent extension of bonus depreciation. For this reason CPN does not see a direct read-through to the PJM auction where it anticipates a similar result YoY.*

Based on the timing of cash flows, real debt reduction is likely to have to wait until 2H16.

Comfortable does not meet complacent: Calpine moved to address investor concerns around its comments on the 4Q15 earnings call when it said that it was "comfortable" with the current amount of leverage. <u>Management is still focused on debt reduction</u> and sees that as a key component of its capital allocation plan but wanted to assure investors that it does not see any liquidity/solvency risk given its 3x interest coverage ratio. We view this as an important clarification as some investors interpreted management's earlier comments as stating that it was not intending to reduce the leverage from the current level. The Net Debt / EBITDA is currently 5.7x ($1.9Bn UBSe 2016E adjusted EBITDA $10.7Bn YE15 net debt) but should decline to ~4.7x by YE16 based on disclosed debt paydown targets.

Calpine is not as concerned about sales growth as it focuses on taking existing market share rather than capturing incremental growth.

Not as concerned with macro electric load trends as conversation shifts to base load vs intermittent: Calpine emphasized that a key component of its story is about capturing market share as a low-cost baseload generator in a world with baseload coal retiring to be replaced by intermittent renewables. We note that this is a bit of a change in tone versus previous years where Texas generators were hyper-focused on demand growth but the continued robust growth of renewables is now drawing more attention. Based upon Calpine's data it still observed above-average 2015A load growth in Texas (+2.2%) compared with a -1% decline in PJM load and -0.75% reduction on the Pacific Coast. In California, Calpine saw positive growth prior to the effects of behind-the-meter solar. Outside California management expects generation at some of its plants to increase even further as delivered costs of gas decline, potentially facilitating up to 10pp improvement in capacity factors for some plants.

Consolidated Edison

Top Three Takeaways:

(1) *After the extension of bonus depreciation we expect to see ED slow its pace of renewable spending quite materially without tax capacity; could this be part of a reasonable pullback for others? The 2017/2018E annual capex placeholder is at $320Mn vs nearly $1 Bn this year.*

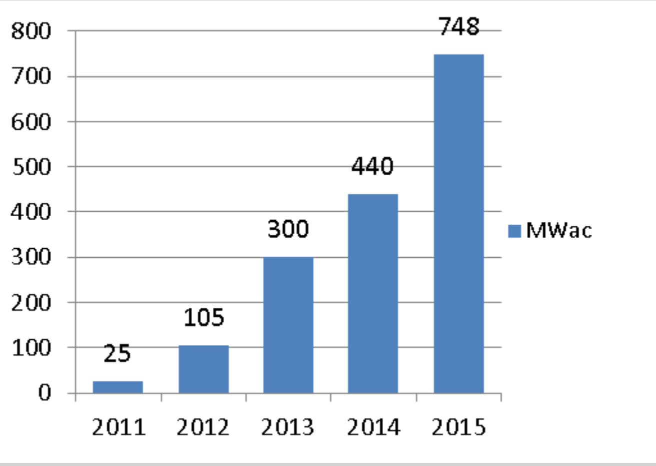
(2) *The recent AGR NY multi-year rate settlement at 9% represents an improvement over the 8.6% PSC Staff recommendation; we assume ED ultimately receives a 9.0% in its current rate cases and this datapoint is supportive.*

(3) *ED has been interested in gas pipeline investments for years but the Mountain Valley Pipeline (MVP) is the first large gas investment for the company as management has struggled to compete with its cost of capital and risk tolerance. While there could be future investments in the future, we do not expect that ED will deploy the same amount of resources here as it did to the renewables segment.*

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

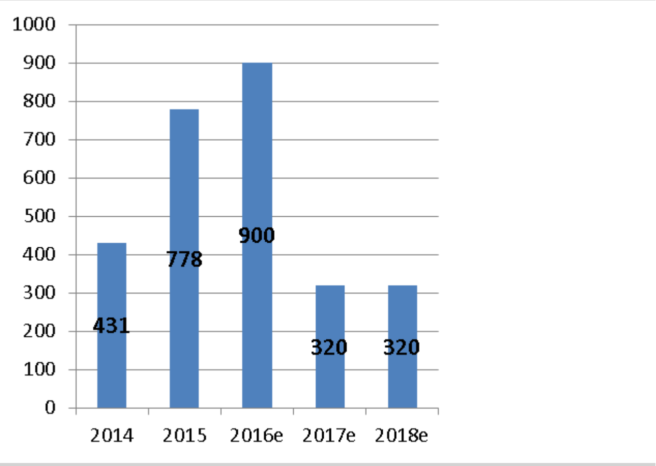
ED received a $224Mn refund ($128Mn at CECoNY) in March 2015 following the extension of bonus depreciation.

Figure 9: Coned Renewable Portfolio



Source: Company Filings

Figure 10: CED Historic and Projected Investments



Source: Company Filings

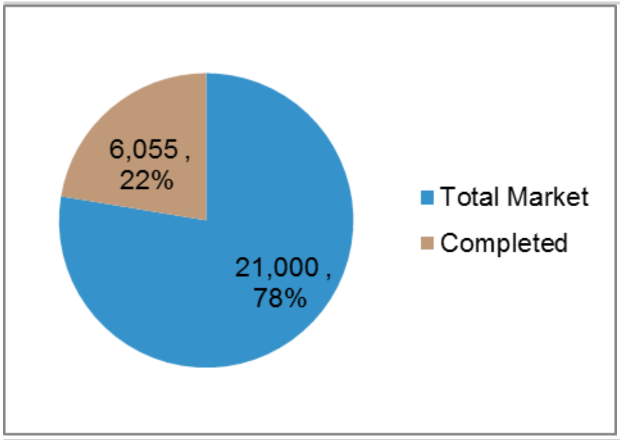
Recent Avangrid rate case settlements at 9% continues trend in New York: Avangrid recently reached a settlement in its pending New York rate cases with a 9% ROE compared with the PSC Staff recommending an 8.6% ROE in September 2015. AGR highlighted that under the settlement it is allowed to earn up to 9.5% before there is customer sharing. In AGR's settlement, reply comments are due on March 25 with hearings to follow on April 7. In ED's rate case the next real update is expected to come in early May when staff and intervenors file testimony. If ED

A PSC decision is expected in AGR's NY rate proceeding by May – this will be an important datapoint for ED's cases.

receives a similar regulatory outcome as AGR we believe that would go some way to meeting investors' expectations/be a slightly favorable outcome.

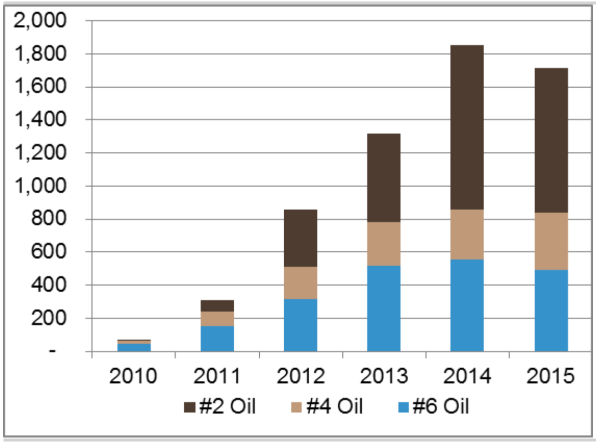
Fuel conversions fell in 2015 YoY but management is still confident on growth: ED disclosed 1,717 fuel conversions in 2015, down from 1,854 in 2014; this is in contrast to projections by Eversource and NJR which expect continued growth going forward. Based upon ED's estimation the payback period has increased to ~3.5 years versus ~2.0 years previously and management ultimately believes its internal forecasts are conservative for additional conversions.

Figure 11: Market for Oil Conversions



Source: Company Filings

Figure 12:



Source:

The details of the AC transmission solicitation were released on February 29th where the parties will submit bids which will be reviewed by NYPA and finally presented to the NY PSC for final approval. Management continues to believe that resolution is unlikely to occur in 2016 but we look for additional datapoints.

Hitting a snare on the selldown of the retail biz

Mgmt remains committed to the sale of this business – despite some apparent issues in executing. We note interest in retail continues to grow, suggesting some modestly improved prospects.

Dominion Resources

Questar acquisition opportunities focused on gas distribution and gas pipelines

With STR already planning to sell the Southern Trails pipeline, D is focused on the growth opportunities from the Questar pipeline, intending to drop only the pipelines into the MLP (about $179M EBITDA of a total $425M MLP-eligible assets), while holding utility Questar Gas and Wexpro reserves at the parent. D does not intend to do any speculative drilling at Wexpro and would only drill if the cost of drilling was included in a cost of service contract (similar to the XEL framework).

STR's utility growth is also projected to be robust, with 1.5%-2.0% growth in Utah and the utility's decoupling clause adding to the favorable profile. The company's Wyoming and Utah utilities are expected to file ratecases on March 3rd.

The deal is expected to close by year-end and is to be financed by the assumption of ~$1.6B STR debt, an additional $1.5B of parent debt, $500M of D equity, and a combo of $2.4B D and 3-yr converts and dropdown cash from Dominion Midstream Partners (DM) (we assume $1.8B/$0.6B). Management states that there is strong interest from the current major holders of DM to expand their positions and suggests that a private offering of public stock may be possible.

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

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

Millstone nuclear likely to be hit with New England gas pipelines

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

Edison International

DRP from 2018-2020 could require spending before rate approval

Southern California Edison's (SCE) proposed $1.8B-$3.1B Distribution Resource Plan (DRP) is split into two phases, with different methods of cost recovery for each period. None of this proposed capex is yet included in the company's forecasts and guidance (nor is the potential for a $300M electric vehicle program beyond the currently approved $11M pilot). For 2015-2017 spending of $350M-$560M, management has filed for a memorandum account to handle recovery through to the 2018 ratecase. However, no response for this request has yet been received (nor has any investment been made), and the company continues to await word from regulators on their preference for strategic prioritization as well as guidance for memo accounting. EIX plans to request the remaining $1.4B-$2.6B spending from 2018-2020 through the general ratecase filing coming in September, with projects likely to be included as part of the typical ~$4B annual capex budget within the rate filing. Management noted that major elements of the DRP from 2018-2020, such as grid resiliency, may have to begin before a definitive regulatory order authorizes recovery, potentially adding some element of regulatory risk to the plan. However, we expect the regulator's forthcoming order modifying, prioritizing, and ultimately approving the DRP should help to mitigate some, if not most of the risk through 2020.

Lower gas pricing creates large ERRA overcollection

The utility's Energy Resource Recovery Account (ERRA) now stands at a $2B overcollection status as a result of lower natural and power gas pricing as well as lower interest rates. The money in this balancing account is returned to customers over time through reduced bills, helping to keep headroom in rates as the company prepares its next rate filing. The account also serves as an inexpensive source of cash financing for the utility at ~commercial paper rates.

Edison Energy Group strategy – going slow

With about $100M invested in three small companies last year, the goal of the soon-to-be-launched (end of March) Edison Energy Group is to act as a service and equipment integrator to a currently fragmented C&I services market. The need is seen as growing significantly in tandem with the expanding universe of new efficiency, renewable, storage, and distributed resource technologies currently available to commercial and industrial customers. Over time, management hopes to grow this to about 10% of consolidated earnings.

Energy Capital/Dynegy: Power Thoughts

Top Three Takeaways:

(1) *ECP partnering with Dynegy for the Engie joint venture was a positive development for power valuations from multiple angles. ECP's willingness to invest in ERCOT and take Dynegy currency both show faith in an out-of-favor market among public investors and a generator with questions around portfolio life.*

(2) *Although the multiple paid was deemed too expensive by few, ECP maintains that it feels comfortable with the price sees opportunity for EBITDA growth in the future. ECP expects 2017 FCF to be weak due largely due to a non-recurring maintenance capex charge but is more optimistic about the future*

(3) *ECP expects the TX market to be subject to a number of retirements. Both Dynegy and ECP cited Coleto Creek as a potential retirement candidate if the market does not recover.*

ECP attempts to leave its imprint in the fossil fuels sector: Energy Capital Partners initially expected to be on the sidelines in terms of deals with publicly traded companies but saw an attractive opportunity to work with Dynegy given its pre-existing relationship. Given an opportunity to re-enter the PJM, New England and ERCOT markets, ECP agreed to engage in talks with DYN to form a joint venture and acquire the US fossil portfolio of Engie (formerly GDF Suez). ECP's original goal was to gain exposure to various different markets and share in the growth of the energy sector. After dedicated significant capital out of its $5Bn fund to fossil investments, ECP does not anticipate further investment in the area at this time.

Attractive deal terms for all parties involved: The key attributes of the deal terms that we discussed in an earlier note [here] is the limited reliance on the public capital markets. DYN will not issue public equity to fund the transaction and ECP uses a bridge loan that converts to equity one year at 1.5x the remaining balance. However, DYN stated that it intends to repay the bridge loan to the fullest degree possible in the first year as this could drive significant dilution in the joint venture if converted to equity. ECP remains comfortable with the valuation compared with comparable transactions recently. Looking forward, the company expects the deal to have positive impacts on their portfolio but noted the free cash flow expectations for 2017 are weak, given the acquired company is in the middle of their capex cycle, which occurs every seven years and consists of maintenance charges.

Retirement Plans: ECP expects an increase in TX asset retirement activity going forward with a significant portion of coal and gas-fired steamers expected to be FCF negative. Dynegy ascribed no value to the Coleto Creek facility given the limited FCF expectations and potential for increasing capex requirements. ECP will have to consider the strategic and financial implications of electing to retire an asset if they are challenged on the merits of that choice.

Exelon

POM not dead yet, but it looks like a long shot now

Company appears to see deal as challenged

On Tuesday, both the DC Mayor's Office and the DC Office of People's Counsel (OPC) announced their opposition to the revised settlement agreement that was proposed on Friday by the DC Public Service Commission (PSC) in the regulator's latest rejection of the merger. With EXC's March 4th self-imposed deadline to complete the deal (and the PSC's 14-day deadline for parties to consider their alternative proposal), it appears that any further compromise may be impossible to complete in time, given the large number of parties that would need to agree. Furthermore, our impression from EXC is that there may not be enough appetite for more heavy lifting after so many delays in what has already been a protracted 2-year process. Principally, the OPC cited the PSC's proposed alternative treatment of the $25.6M residential rate offset provision as having "nullified the benefits" of the merger for residential customers. Press reports (Washington Post and WTOP Radio) cite the Mayor's opposition to the PSC's desire to create an escrow sub-accounts for PEPCO for a portion of the $78M proposed "customer investment fund" contained in the original settlement.

PSC Chair Betty Ann Kane told reporters that the escrow accounts would enable the PSC to monitor and audit their use, and that without them, she was concerned that payments "*would be subject to diversion to the general fund — which is something that has happened time and time and time again*."

As a reminder, the original settlement was arrived at after the PSC's initial rejection in August 2015. That settlement had been agreed to by various parties, including the OPC, the District Department of Energy and Environment, the Office of the Attorney General, and the Apartment and Office Building Association, among others. However, in this latest rejection on Friday, the PSC gave settling parties 14 days to review the regulator's alternative proposal and accept or reject it.

The Mayor's and OPC's rejection appears to have been swift and the PSC's requirement for a simple up/down vote appears to leave little room for compromise at this time. Nevertheless, we also take note of the OPC's appeal to "all parties and consumer participants to this case" to "not lose sight of the real issue in this case—the protection of our most vulnerable residents," which may indicate a willingness to accept a modified alternative should the PSC and EXC be open to pursuing one with other parties. However, it is far from clear at this time whether either party would be willing to continue the process should it appear necessary to devote significant further time and resources, particularly since PEPCO has already missed at least nine months of its normal ratecase cycle (dragging out the accretion math further).

Prior to these latest developments, EXC had estimated that improving the PEPCO utilities (e.g., noting that MD utility BG&E is now earning a 10.2% ROE) would likely require the immediate injection of at least $1B of capital and take "a couple" of ratecase cycles with a timeframe of 24-36 months.

Kicking off the decision suggests optimism still

Mgmt noted last night it would remain open *past* its initial 'go/no-go' date of March 5th, likely extending out by a week to the DC PSC's deadline to accept the proposed terms of its revised offer. We suspect more funds may well need to be offered from EXC to parties to placate all demands.

So what would EXC do next?

EXC's current utilities are expected to grow net income by 7%-9% annually.

Management told us they would most likely repurchase the 57.5Mn shares used to finance the pending deal via either an accelerated program or open market transactions. Exelon originally divested some ExGen assets to help finance the POM transaction and those proceeds will help bolster the debt reduction plans at the merchant subsidiary. EXC would have the capacity to pay down $4.8B of debt rather than the recent commitment to reduce GenCo debt by $2.9B over the next five years (out of a total ~$8B GenCo debt, including $2B of project financing).

EXC long-term game plan – become more regulated

Regardless of how the POM deal turns out, EXC views its merchant power business as essentially shielded from significant commodity exposure through the retail business, with the resulting FCF reinvested in the utilities that are valued at industry multiples near 16x 2018E earnings. Over time, management hopes to achieve FFO/Debt at the utilities of 17x-18x while emphasizing organic growth opportunities, especially in the development of cybersecurity. Looking past PEPCO, the company would likely look at smaller targets, such as nearby munis and co-ops, also emphasizing the cybersecurity opportunities that a larger platform could bring to these small independent utilities.

Gas asset advantages

Noting that recent transaction P/E multiples have been too high for their taste, management nevertheless believes that gas utilities are attractive targets as their equipment replacement cycles are only 20-30 years vs. electric utility assets that can last as long as a century.

Retail book a good hedge for merchant generation

EXC is seeing $2-$4/MWh margins for their fixed-price retail contracts (lower for indexed contracts), with about $200M of margin for every $1/MWh. The retail book now stands at 205-210 TWhs vs. the historic low end at 160 TWhs. The company advised not to view too much correlation to their margins from the recent NJ Basic Generation Service (BGS) auction, which resulted in significantly lower risk premiums last month vs. the previous two years. As a hedge, the retail book provides straightforward risk mitigation in a declining commodity price environment, with rising price risk mitigated through proper risk management and a large physical baseload supply portfolio. Retail risk remains in ERCOT, where customers underestimate the risk of volatility and contract pricing doesn't reflect this, although EXC emphasizes their ability to go to the spot market if retail prices are too low.

Clinton in trouble; Quad Cities in better shape

Without legislative support in Illinois for its Clinton nuclear facility (September deadline followed by a veto session), the MISO-located plant will likely face a near term shutdown decision this fall, whereas Quad Cities would likely be able to survive providing the plant continues to clear the PJM Capacity Performance auction. Fundamentally, EXC does not believe that their nuclear fleet is being given proper value by the market at only 5x EBITDA, especially considering the extra value of reliability and being carbon free while earning 15%-20% ROEs for the Genco. See our companion note today on the future of Illinois nuclear.

Ohio alternative PPA proposal essentially pits the carbon reduction value of nuclear power vs. renewables

EXC continues to note the need for reforms in both capacity markets in order to realize the full value of nuclear units given their (1) high reliability and baseload characteristics (2) lack of fuel price correlation to more volatile sources, especially natural gas, and (3) carbon free output. In Ohio, the company's alternative 3,000-MW PPA proposal for Ohio noted $2B of customer savings vs. the FirstEnergy proposal, although this includes the value of carbon reduction, which is handled by FE through the shutdown of coal and substantial support for 900 MW of renewables. From our view, EXC's proposal essentially asks Ohio to skip over an investment in FE's in-state renewables and instead purchase out-of-state nuclear power. While this is an arguable trade-off, we note that the FE and AEP merchant coal fleet settlements in Ohio appear aimed at accomplishing more than just carbon reduction, with additional eyes on economic development and a controlled transition period away from the state's reliance on coal.

FirstEnergy

PPA: Mgmt remains exceptionally confident. However, expect FERC to act only *after* the PPA is approved by Ohio. We expect the exemption on the Affiliate transactions, enabling a review of the contracts.

Bidding of the plants: Be careful what you wish for: despite pressure from other parties to shift how FE bids in its units into the capacity auction – we note that a shift in the bidding approach could well drive down clearing prices, as units are no longer the 'clearing' assets in the auction.

Plan B: We look for mgmt to articulate in coming periods its plans on a legislative alternative should the path not work. This would seemingly re-regulate the state via a state-wide mandate for procurement, centralizing the retail options rather than putting assets back into ratebase.

- The prospects of this re-regulation would allow for all generators to sell at long-term fixed price terms; this would seemingly be attractive for DYN among others.

Following suit in West Virginia: We continue to expect W Va to pursue procurement into rate base of the Pleasants plant as part of its latest IRP filing. Expect this process to still take some time.

Balance Sheet: Mgmt remains below its min credit rating targets at 12.8%, a hair below the 13-14% requirements. The agencies remain patient ahead of an outcome with the PPAs

NJ: Will file another rate case this year, largely to recover ~$25 Mn in O&M (seemingly unrecovered in the last case). Improving reliability will require more spend. If successful, expect a stimulus spend project to follow suit.

Welcome, Chuck: The recently appointed CEO is still largely upbeat on execution of his strategy towards a regulated orientation for the company.

FirstSolar

We expect shares to trade back into the upper-$60s, potentially testing its recent highs ahead of its April 5th Analyst Day. We suspect the bulk of the focus will be on technology roadmap, but we see a potential scaling of MWs and deployment of its balance sheet as mgmt seeks to capitalize on its net cash position amidst the market downturn to capture market share. Management appears more confident on its prospects given the ITC extension domestically, adding to EPS upside as deployment translates into expanded earnings opportunities.

Mgmt noted that they would have liked to push more projects back into 2017-2018, but had little flexibility given agreements with the counterparties. Only one project (East Pecos) had some flexibility, but the counterparty required that it be delivered in 2016, giving FSLR little room to push it back. Between CA Flats, Switch Station, and Cuyama collectively 300MW of projects are being pushed out of 2016.

In contrast to the financial concerns – we expect the upcoming Analyst Day to focus on improvement in the outlook. The effort will be to drive efficiency, total project cost, and ultimate scaling of its production to become more of a global manufacturer of panels. While clearly challenging to embark upon a further meaningful capacity increase, we suspect management will offer tantalizing metrics if successful.

Mgmt continues to book additional projects, emphasizing its expanding book-to-bill ratio which grew YoY sequentially in 2015. Expectations on the international expansion remain strong, with this being a key story to follow with investors seemingly wary of the emerging markets given GLBL's underperformance. That being said, mgmt looked to quell the concerns, saying there is not a significant opex risk in the international markets, as they will pursue module-only strategies in high-cost markets.

FSLR stated that the union labor, along with the more costly permitting in CA have meaningful impacts on the PPAs, with FSLR seeing CA PPAs in the 6-7c/kWh range compared with 4-5c/kWh in lower cost markets. GTM reiterated this point in a group meeting, even stating that they've seen CA PPAs in the 8c/kWh region.

Reiterating what they stated on the 4Q15 call, mgmt noted that the updated pipeline reflects a significant increase in share for North America, with the share for all other regions decreasing or remaining relatively unchanged since 3Q15. In the past quarter, the pipeline increased by ~3GW, nearly all in the US. Mgmt stated that this had less to do with changing their strategy as a direct result of the ITC extension, but rather the counterparties having greater transparency and confidence in the US market outlook.

As for the economics of solar going forward, mgmt said that they think they can be competitive bidding for peaking power with combined cycle gas currently in some areas of the US. As for a longer-term outlook, mgmt noted that solar + storage has the capacity to displace gas peakers, and that this could start being competitive around 2020.

Relative to potential capacity expansions, the company has 8 lines mothballed currently. The company would need to find a facility that could house the lines,

with the current plants having no room for expansion. Mgmt noted that this is a 18-24 month process to find or build a facility, and outfit it with the tools that are being stored, along with updating those lines for the new technology.

Regarding expansion plans from technological and geographic perspectives, mgmt prefers the partnership model, as this provides them with more flexibility to get in and out of markets. FSLR is pursuing this in the storage market via a partnership with Younicos, and geographically the look to find local partners in in regions that they expand to for development or module sales purposes.

FSLR reiterated the point heard by several players, that the development market has become more disciplined in the past 9 months with SUNE's situation escalating and many YieldCos not being able to pursue the same aggressive growth strategies. FSLR noted that they will look to flex the balance sheet and take advantage of opportunities that arise out of the more stable market.

Balancing the considerations into the Analyst Day.

We see a few factors as warranting greater attention into the Analyst Day metrics and earnings quality:

- First, what specific projects will be recognized in each year? Providing a multi-year continued consistent upwards trend in EPS will do much to offset concerns around a single year benefit in 2017 from certain contracts
- Second, Scaling of the MWs: The question remains just how much larger it will scale its volumes given the technological benefits the company has versus peers. While clearly some degree of revision is expected, we note SPWR has promised to 'triple' its capacity by 2020, and in turn doubling EBITDA. We suspect such vast promises will garner little immediate credibility today without a roadmap in place.
- Third, where are EPS expectations? We suspect shares will trade higher if the top end of the EPS guidance range for 2017 is north of $4 in EPS, with a disproportionate jump should it have a $4.50 range.
- Total margin remains the focus as increase sale of modules-only. We see risk that margin %'s may increase, but total margin in nominal ($ Mn) terms decline on lower revenues.

GTM Research Round Table

Our guest from GTM Research, Shayle Kann, noted that while the solar market has booked 15 straight years of growth, there is not much correlation between the growth of the segments, as they have trended separately from one another. He specifically noted that while resi and utility have grown substantially, the commercial space is at a relative standstill given the bifurcation in the space, and the difficulty in financing deals given the lack of uniform credit standards for commercial customers.

Kann stated that utility-scale build represents over half of the market, and that it will remain this way for the foreseeable future, as state RPSs and improving economics has driven this segment. With PPAs below 5c/kWh, the economics can compete with natural gas in some states. As for a potential headwind for utility build, the reform of PURPA laws could go against the solar players in some states, where utilities are fighting to get the PURPA mandated contract lengths down to ~5 years, from 15-20 currently. This is mostly applicable in the Midwest and Northwest. *We continue to expect reform of this market, which could represent upwards of a ~quarter of the total utility-scale prospects in the US per GTM.*

While the merchant market in Texas gets discussed a great deal the market hasn't actually taken off to the extent people are expecting, with only 2 merchant projects being done in TX to date. While developers are banking on this market taking off, it remains to be seen if there is significant volume to be had. As for the Southeast, Kann mentioned that Georgia has a need for capacity, with coal retirements expected, and solar likely competitive with gas for the replacement load. Additional markets in the Southeast that are primed for growth are the Carolinas, with South Carolina the more 'untapped' of the two.

A trend that GTM sees playing a more significant role going forward is the retail procurement of wholesale solar, as demonstrated by Apple's data center PPA. There are currently ~1.5GW of contracts, but GTM sees this new class of customer as having the ability to grow significantly in the US, mainly due to the emissions regulations.

While the NEM reforms in Nevada included retroactive legislation for existing customers, GTM doesn't believe that this will be the norm as many states will not be able to pass such revisions due to the backlash. Additionally, outside of the retroactive reform, GTM doesn't expect more general NEM revisions in other major states to be as damaging as what was done in NV. Specifically, GTM doesn't believe resi solar will be killed in CA and MA, with the cap likely to be resolved in MA, potentially in exchange for a minimum bill.

Hannon Armstrong, HASI

HASI mgmt said that they had been worried that the YieldCo bubble would burst for roughly 18 months, as they saw players exercising overly aggressive bidding strategies for projects and PPAs. With the bubble burst, mgmt noted that there is a greater importance on the strength of long-term partnerships, as players are less willing to take counterparty risk.

In terms of asset residual value, HASI believes that this should be a secondary focus, and should primarily be a hedge against power plant risk, as things normally go wrong with power plants over 20-30 year lives. HASI sees many players valuing assets inclusive of significant value for the residual life, but that this leaves little room for issues to arise at the assets.

As for debt vs equity, mgmt said that TERP's statement of equity being cheaper than debt was eventually proven incorrect, with HASI believing that the return prospects on the debt side are higher in the YieldCo space. In terms of HASI's prospects given the withdrawal of capital from the YieldCo space, mgmt stated that the company is up 70% since the YieldCo bubble burst as economics for land leases are better, which has helped the company's fundamentals.

HASI expects a transition in the YieldCo space away from sponsor models, and believes that some players could bring development in-house. Among the various issues with the sponsor-model, HASI sees the dependence on a sponsor's health as the biggest concern, with SUNE and Abengoa the key examples of sponsors bringing the YieldCo down with the ship. Additionally, HASI stated that there needs to be a healthy medium between development and acquisitions, as an acquisition heavy strategy can lead to overleverage and dependence on favorable valuations which did not exist at the height of YieldCo competition. The largest unknown currently is the understanding of which groups will be the long-term asset holders, and which groups will be the long-term capital providers, but HASI believes that the independent YieldCos have a role to play on both fronts.

HASI maintained that energy efficiency is still the priority for the company, with utility-scale wind then solar taking secondary roles. Additionally, HASI doesn’t want to get involved with the residential solar players, as the company doesn’t believe they will be around for the long-haul. HASI prefers to deal with engineers, which is why they work on the utility-scale side, and believe this is a more viable and long-term market.

Eversource

What's the order for the big transmission projects? Focus on the Latest New York project *first*.

We increasingly see the Clean Energy Connect project as the immediate solution to address the ongoing procurement in New England from MA/CT/RI. We suspect the combination of characteristics provided to the region beyond renewable energy credits (RECs) – including both energy and firm capacity (given firming backstop from hydro in New York), makes this a viable competitor. We emphasize the competitive process could yet mean the state. Overall, the project is slated for ~1.1GW; this would align against ~700MWs procured between MA and CT, with most of the balance procured by RI (just for deliverability) in an ideal world.

Gas Pipelines: Getting comfort

We remain confident on Access Northeast. We look for procurement activities to be finalized in the ~October timeframe from all three relevant states (MA, CT, and RI). With all but the Bridgeport Harbor project built along the Algonquin pipeline, the need to expand the pipe to provide additional generation solutions will only add the carbon footprint of the region.

KMI has suspended development operations pending further work

We maintain confidence in the ES/SE Access Northeast project over KMI's quasi-competing gas project. We note the KMI project was originally intended to serve native gas LDC load and has seemingly failed to procure for the minimum ~800k Dth/d to move forward at this time relative to the ~600Dth/d procured. That said, we suspect further procurements could yet manifest themselves. The state of MA appears quite keen to see this project move forward. A further question on executing remains citing of this project both in New York (as an extension to other existing pipelines including Constitution) as well as in Western Mass where local opposition has proven heated.

New Jersey Resources

SRECS much higher than projected

Current pricing for NJ Solar Renewable Energy Certificates (SRECs) for 2016 vintage stands at about $278, or 86% of the $323/MWh alternative compliance payment. This remains significantly above the ~70% level that NJR had initially forecasted for max pricing at their Analyst Day in 2015. As we highlighted in our 1/25 report "SREC Prices Indicate Continued NJ Solar Challenges", the higher pricing is reflective of continued permitting and other construction bottlenecks in the state that have kept the state short of the increasing amounts required to be purchased by load under the 2012 state law. NJR also explains that it reflects the approaching saturation points for solar in the state, particularly grid scale located at dwindling numbers of addressable commercial, industrial, and agricultural sites. In contrast, residential penetration is only 10%-15%.

Furthermore, NJR also notes that the bid/ask spreads for SRECs have narrowed surprisingly to only $2.50 from historical trends of $10-$15, reflecting the increased bid activity. The company continues to project 170k-172k production of SRECs from its own portfolio, and has been an aggressive seller to hedge in the current high priced environment.

"Comfortable" with Dominion Midstream (DM) ownership

Recall that in 2015, NJR and National Grid sold their combined 25.9% stake in the Iroquois gas pipeline to Dominion Midstream Partners (DM), the MLP of Dominion Resources. As a result, NJR received $61.1M of DM LP units with a lockup period through Aug 2016. Regarding the potential to increase their ownership stake through DM's forthcoming (likely private) offering to help fund its purchase of Questar assets, NJR management said they are comfortable with the current position.

Solar vs Wind decision

In recent years, NJR has been executing a shift of their national renewable portfolio increasingly into wind assets to reduce exposure to what was believed to be a declining and expiring profile for solar investment tax credits (ITC) as well as the volatile SREC market. However, Congress' recent 5-year extension of both the solar ITC and the wind production tax credits (PTC) may change the company calculus a bit, particularly with regard to timing of the shift. We await an update on the 2Q earnings call.

NextEra Energy

Top Three Takeaways:

(1) *NextEra is one of the few companies with the balance sheet, long-term tax appetite, and development expertise that will allow it to gain market share of the expanding pie of renewables development. Mgmt emphasized that the majority of its recent deals have been driven by economics rather than environmental policy (RPS/CPP) and that it sees significant renewables growth opportunities even without the Clean Power Plan.*

(2) *Following the recent developments in the Oncor change of control proceeding in Texas, management reiterated that it will be disciplined when it comes to further M&A and will not chase growth. The latest regulatory developments in M&A for CNL, POM, HE, and Oncor will likely factor into the risk assessment that management teams use when creating offers for any future deals.*

(3) *Even though we expect a positive update on future renewables development we do not anticipate that management will update its long-term EPS growth target as the 6-8% EPS CAGR already reflects optimism around renewables growth.*

NEER set to gain share in a growing market – without sacrificing margins

Competition for wind development has been declining: NEER has observed a decrease in competition but has not seen any real increase in % margins. Many of its main competitors from five years ago are no longer in the business although there have been some names that continue to appear (ex. Invenergy). For example we believe that the financial stress at SunEdison and recent management changes have impacted the FirstWind subsidiary's ability to compete in the market, a benefit for NEER and others. Solar competition continues to be healthy with lower barriers to entry but NEER still touts its advantages over smaller developers.

What does management think about further M&A? Management commented that it is challenging to extract meaningful accretion from regulated acquisitions when paying a significant premium but it continues to be open to the idea if the right opportunity presents itself. Echoing comments from the March 2015 Analyst Day, the company believes it has a very transferable skill set on utility operations (cost control, generation planning, etc.) that it could bring to other utilities. The company's preference in M&A would be to pursue utilities that are not earning at their allowed ROEs and/or have opportunities to extract costs to create headroom for capital spending opportunities. If NEE were to pursue a transaction it would not want lose its BBB senior unsecured S&P credit rating. Bringing the conversation back to the tangible, management repeated that it views Oncor as a solid asset based upon its disclosures but will remain disciplined regarding how much it can pay for it.

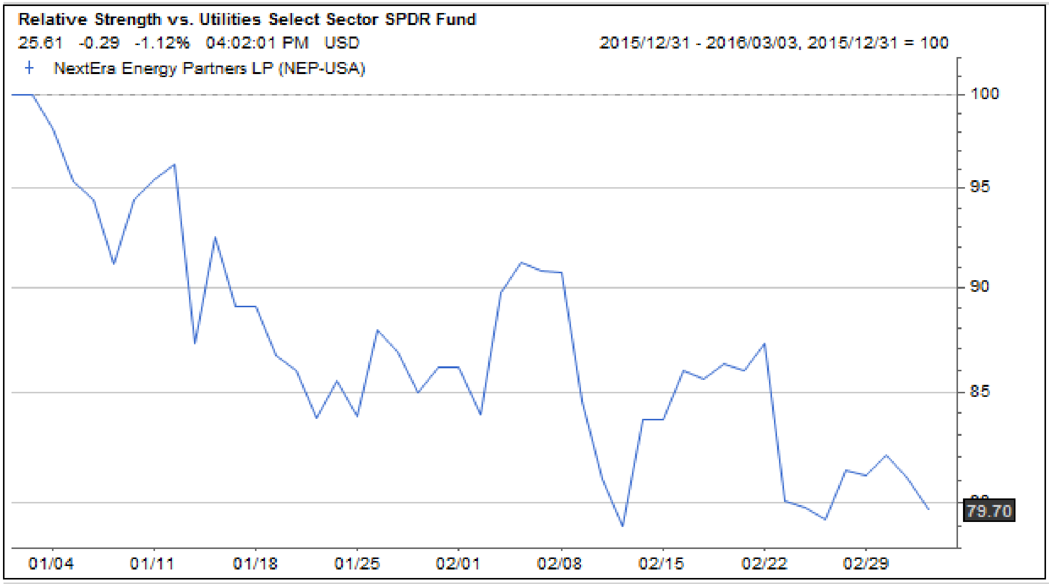
Factors that management considers:

- Ability to reduce O&M
- Opportunity to deploy more capital with the headroom created from less O&M
- Under-earning
- Maintain or strength the balance sheet

Still working to execute on NET expansion: When NextEra announced the NET Midstream acquisition in 2Q15 it highlighted $300Mn of future potential expansion investment opportunity and management is still working to execute on the capex in the current environment. At the time of the announcement the expansion would drive 2018E adjusted EBITDA/CAFD to $190-$210Mn/$135-155Mn, up ~$50Mn/~$30Mn from 2016 guidance at the time.

With respect to the most recent drop-down disclosed on February 22nd management is pleased that it got the financing completed but is hopeful that it will be able to execute the next transaction at a lower NEP yield.

Figure 13: NEP Relative Performance



Source: FactSet

NRG Energy/NRG Yield

Top Three Takeaways:

(1) *In attempting to refinance some of its upcoming obligations management is hopeful that it can keep the interest rate/terms in tact rather than seeing incremental FCF erosion from higher financing costs. Adding more secured debt could be a creative solution to generate more capacity to reduce NRG corporate recourse debt.*

(2) *Due primarily to its leading retail presence in ERCOT, NRG believes it is the best positioned to withstand the near-term challenges in the market and be able to benefit more consistently if the market tightens.*

(3) *Although some investors had expected a complete refocusing on conventional generation, NRG remains committed to its Renew subsidiary which targets larger scale renewable projects. An update with respect to a potential divestiture or partnering for Home Solar is expected in 2Q and investors' expectations for proceeds/value are quite low given the stress in the residential solar market.*

Objective of capital allocation is to maintain the sustainability of the FCF: The capital allocation debates that Talen discussed on its earnings call and in our management meetings are quite similar to what is currently facing NRG Energy. NRG does not want to ignore the near-term maturities which explain why the current plan is to reserve $325Mn of capital to dedicate towards the 2018 upcoming obligation. The objective is to refinance as much of the $968Mn 2018 recourse senior debt as possible while keeping the interest rate/terms at least in-line with the 7.625% current NRG Energy senior note. Aside from the refinancing the 2018 debt management remains broadly committed to total debt reduction in

2016 with any other excess cash. This could be supplemented by adding up to $1Bn of secured debt to the assets to help repurchase corporate obligations (again a similar strategy as Talen has articulated). It is unclear how much of this latitude is at NRG assets vs GenOn but we would expect management to aggressively pursue debt reduction at GenOn to improve the outlook for the non-recourse subsidiary.

Optimistic that it will outlast peers in ERCOT: Management expects its fleet to fare better than most in Texas because: (1) it has already taken steps to cut costs at its assets, particularly the coal and nuclear capacity; (2) the retail portfolio compensates for more challenged economics at the plant-level and is a natural hedge; (3) geographic advantages of being closer to load centers and further away from renewables; and (4) the magnitude of environmental compliance liabilities expected by management is lower than what it models for many peer generating facilities. On the last point NRG has already invested into Parish and Limestone but does acknowledge that it could face regional haze related spending towards 2019. It remains to be seen exactly how material capex obligations will be for NRG and peers into 2020 in ERCOT but with NRG taking a more holistic view of its wholesale & retail asset mix we assume it has a higher asset-level tolerance for incurring obligations in the market.

Despite repeated questioning management remained adamant in the outlook for its portfolio of coal and nuclear assets (and disclosure of a significant $19/sh write down which was driven primarily by Texas coal), stating that it looked to peers worse positioned in the state to retire first.

What are the GenOn Risks from our vantage?: We expect the dynamic between creditors and management to heat up in coming months as focus on restructuring options for the highly-leveraged but non-recourse subsidiary grows. 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. We suspect creditors will push to cut the size of its support payments back to the parent, with the ~$200Mn outsized relative to the ~$300Mn-ish forecasted EBITDA, particularly given the shrinking asset pool. 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 consistent at least with the asset sales, if not materially more. We see Street estimates as anticipating reductions between 25%-75% off the current level. The further question is how much of this allocated cost could be reduced in the event of a separation. Further, to what extent can asset sales reduce this overhead too? Net-net, this remains a large overhang on the stock.

We ultimately expect NRG to attempt a tender offer well below par.

Remaining committed to the renewables strategy: Perhaps in contrast to growing expectations, NRG Energy remains committed to expanding its renewable business on the utility-scale side and staying the course on its ownership in NYLD. We see a structural issue should NRG even evaluate selling its ownership here and see uncertainty on what redeployment prospects would be. Rather, we suspect a decision on GreenCo in 2Q will lead to a partnership rather than outright sale, providing income to the company, and retaining some modest exposure. A win-win in our view, turning a negative to a positive.

Still view renewables in favorable light, just not residential solar: Management is in active negotiations with a potential buyer/partner for its Home Solar business and remains committed to providing an update on resolution in 2Q.

OGE Energy (Unrated)

Top Three Takeaways:

(1) *Despite having its larger $1.1Bn environmental plan denied by the OCC in December, management is optimistic that it will ultimately receive approval to add scrubbers to Sooner. If the Commission votes no, management will convert the asset to gas (~$100Mn cost) as it does not see a renewable solution as feasible given the EPA imposed time constraint.*

(2) *Despite all of the noise around the Sooner retrofits, management is committed to its current Mustang plan as the original plant was built in the 1950s and is considered very inefficient. Investor attention continues to focus on these two environmental projects which represent approximately half of 2016E capex.*

(3) *Despite the Enable write-down the investment is doing exactly what management intended: generating strong cash flows to facilitate dividend growth and finance the expected environmental capex without requiring equity. OGE is happy with its business mix today but could be open to adding more Enable if the price is attractive ("never say never").*

Scrubbing the scrubber plan: OGE continues to pursue pre-approval to install scrubbers at its Sooner coal assets and last week the Oklahoma Corporation Commission (OCC) denied two intervenor motions by a 3-0 vote to dismiss the proceedings. This follows a December OCC action rejecting OGE's plan to install the scrubbers and other generation projects. The latest filing is narrowly focused on the $450-$500Mn scrubbers and management is hopeful that it will be successful. Management has requested a yes/no decision by **May 2nd** so it can begin construction in order to be compliant with EPA regulations by YE18. OGE does not believe it is either logistically feasible or economic to build enough wind to replace Sooner in a timely fashion as they only receive 5% capacity credit for wind construction. If the Commission votes no then OGE will begin converting the assets to gas. This OCC decision is expected to be a simple 'yes/no' and if yes OGE will file two more rate cases for recovery, carefully managing timing to reduce regulatory lag to the greatest degree possible.

As of the 4Q15 call OGE has spent $130Mn on Sooner to date and is confident that it would receive recovery of that capital.

Based on comparable assets, management estimates that a gas conversion could cost ~$100Mn but it has not conducted detailed studies yet.

Going ahead with Mustang, regardless of Sooner outcome: With respect to the Mustang Modernization Project, management is committed to proceeding with adding 400MW of combustion turbines by mid-2018 to replace the aging gas facility (1950-1959 vintage). $330Mn of capex is expected in 2016-2018 with the majority of the spending in 2016-2017E. OGE is not concerned by the Commission's actions around Sooner and believes it expects a constructive regulatory outcome when it files a rate case for recovery of the assets. Currently the filing is expected by the end of 2017 but could be accelerated along with the asset construction; as mentioned previously, managing the timing between the cases to minimize lag is a key consideration. There is no pre-approval process for this spending like there is available for Sooner.

Never say never on adding more Enable but comfortable with the business mix today: Following CenterPoint Energy's announcement that it is undertaking a strategic review for its Enable Midstream investment, OGE stated it was comfortable with its current business mix but could be interested in adding more Enable exposure if the price was right.

Residential and commercial sales carrying the load: Strong customer growth has been the driver behind +2% retail and commercial weather normalized load growth recently which more than offset the impact of -4% industrial sales. Total sales are forecasted to grow +1% in the future due to the more diverse nature of the economy.

No change to above-average DPS growth target even with latest OCC developments: Management still expects 10% annual dividend per share growth through 2019 despite the Enable Midstream impairment. No equity is expected for the foreseeable future and OGE does not forecast corporate taxes until 2021 due to the extension of bonus depreciation.

Pattern Energy

PEGI mgmt. noted that discussions of reintegration strategies are ongoing between Pattern Development (the private DevCo), and PEGI. Mgmt stated that the originally laid out integration plan didn't work because they expected to grow PEGI to a large enough level so that it could purchase the DevCo, but the DevCo grew at a similar rate fairly unexpectedly. Additionally, the downturn in PEGI shares, and the YieldCo sector more generally, has not aided the plans. While mgmt. did not disclose the details of the structure of a potential reintegration, they noted that only preliminary discussions are taking place, and also stated that Riverstone would support the process.

Regarding the payout ratio, mgmt. is still targeting 80%, and doesn't expect to target a higher rate than this given the uncertainty in the market. Assuming a no growth scenario, an 80% payout tied to $149Mn of CAFD and 75Mn outstanding shares would equate to a dividend of $1.59/sh in 2016. Mgmt is not guiding to this, but just offered the metrics as an illustrative example.

From a market commentary perspective, mgmt. highlights that acquisitions made at unsustainable levels created the downturn in the YieldCo space, with the impact being PEGI share price volatility than the company would have ever imagined. Regarding the unsustainable acquisitions, the company noted that they have seen the market become more normalized recently, with the values for the larger projects coming back to less aggressive levels. That said, YieldCos have largely not been making acquisitions recently due to the low equity levels. Additionally, smaller sized investments, specifically in smaller markets, have seen less fluctuation in valuations, as opposed to the highly sought after large projects in major states.

PEGI focuses on after tax carry forward levered IRRs as the key metric, and note that they key range is in the high single digits, which is where they look to get deals done at. For projects past COD, PEGI has seen low to mid-teens for IRRs.

The company noted that wind production has been light once again in 2016, on the back of below normal production in 2015 as well.

PG&E

Expect a final $160M writedown with the GT&S decision

We expect a Proposed Decision for Phase 1 (revenue requirements) of the Gas Transmission and Storage (GT&S) ratecase any day now, having already pushed passed an earlier year-end 2015 expectation. Consistent with the earlier April 2015 decision to disallow $850M of safety spending in the case, we also expect the utility to write down the last $160M expense piece of this total at the time of the final decision, with the remaining capital expense already accounted for on the balance sheet (~$400M in 2015 and another ~$300M embedded within the 2016 capital budget). Other case updates include:

- **San Bruno criminal trial** – set for March 22 and expect a 6-8 week jury trial. The recent decision by the judge to reject a gross losses calculation reduced the potential penalty from over $1B to about $500M. A decision on whether to allow gross gains in the penalty remains deferred, although we note that without this provision, the maximum penalty would shrink to a mere $6.5M at $50k/violation/day.

- **Ex-parte reporting Order Instituting Investigation (OII)** – expect a March 21st decision on whether the facts of the case merit going forward, with a March 23rd prehearing if the answer is yes.

- **Gas distribution recordkeeping** – SED has recommended $112M penalties and City of Carmel recommended ~$650M. PCG has already been fined $11M for violations. Expect the record to close by the end of March with a decision afterward.

- **Safety Culture OII** – while not an enforcement proceeding (more of a lessons learned and improvement process), the Public Utility Commission (CPUC) is still in the process of hiring an independent consultant to run it.

- **Distributed Resource Plan (DRP)** – although the company (and other California utilities) is awaiting a response from the CPUC regarding policy and plan modifications, the utility is already including capital spending for DRP-related projects within its 2017 General Ratecase (GRC). Full execution is expected to occur over several ratecase cycles.

- **Electric Vehicles (EV)** – the utility has filed two plans in response to the rejection of its initial 25K charging station proposal: (1) a 2,500-station plan in compliance with the CPUC's rejection, and (2) a 7,500-station counteroffer with the justification that this is the minimum size needed to create a meaningful dataset from an EV pilot.

- **TO 17 FERC Transmission case** – continues to move forward with the next settlement conference in March. These annual settlements are always black box, although management's guidance is to assume the targeted 10.4% California jurisdiction ROE across the entire capital structure (including these FERC jurisdiction assets).

- **Cost of Capital** – although the company would be happy to extend another year, the current plan is to file in April 2017 for rate changes effective Jan 2018.

On the dividend, PCG remains committed to addressing the payout ratio this year (to bring more in line with industry averages). This is not dependent on the outcome of the GT&S case or the 2017 GRC.

Pinnacle West

All-source RFP coming this month

In March, we expect the utility to issue an all-source request for proposals for new generation in 2020+. This will include combined and simple cycle gas turbines, batteries, and other sources capable of replacing approximately 1,300 MW of power purchase agreement (PPA) contracts rolling off, including PPAs for the Gila River and Arlington facilities through 2019. Renewable sources are not expected to feature prominently as the bulk of the need is for more flexible capacity capable of providing ancillary services to help stabilize the grid. We expect the company to propose a ratebase option for Gila River and/or Arlington with the argument being that ownership provides a steadier base for stable pricing over the long term (vs 3-5 year contracts that reset at market). Should the ratebase option be chosen competitively under the RFP, the utility would plan to file an adjustment to the upcoming June ratecase filing in October after the procurement is actually accomplished.

Expect State Supreme Court to rule on rider authority by mid-2016

Recall that In Aug 2015, the Arizona Court of Appeals ruled for the Residential Utility Consumer Office (RUCO) in their case against the Arizona Corporation Commission's authority to implement a "system improvement benefit" charge on behalf of Arizona Water, a small water utility. The ruling declared that certain automatic adjustment rider mechanisms (perhaps all of them) are unconstitutional since they violate the requirement for regulators to determine a public service corporation's fair value when setting rates. The potentially larger ramification of the ruling is that it might apply to many other more important riders in the state, especially ones that ratchet only upward, such as the Lost Fixed-Cost Recovery (LFCR) fee currently charged to rooftop solar owners and the Transmission Service Agreement (TSA). Some adjustors may be safe from challenge since they move in both directions, such as the Power Supply Adjustment (PSA) mechanism.

Fixed charges and new Time of Use (TOU) rates sought

The current Lost Fixed-Cost Recovery (LFCR) mechanism covers only about 40% of revenues lost to conservation and distributed generation through a surcharge, leaving about $11M ($0.09/sh) of the revenue requirement uncollected. In the next ratecase, we expect the LFCR to be eliminated but also for the revenue requirement to be trued up to actual sales in the historic test year. From this new baseline, PNW intends to seek full decoupling (a relative long shot) as well as a shift for Time of Use (TOU) demand rates to later in the day in order to better match peak load with peak net metering payments. <u>The shift would likely result in fewer payments to rooftop solar</u> as peak midday solar generation is earlier in the day than likely proposed TOU rates. The company is also seeking to fix a higher 35%-40% portion of the retail rate structure, which would still be substantially below the 70% of the utility's fixed costs. Even without decoupling, we see the

TOU shift and higher fixed charge as potentially stemming the tide of rooftop solar subsidization that has been occurring in Arizona as a result of generous net metering policies. The result should be stronger load growth that would help offset the remaining lost revenue problem that occurs as a result of energy efficiency, conservation, and distributed generation at utilities that collect revenues based on volumetric rates.

Portland General

Still confident on Carty

POR remains confident that the 440-MW Carty plant will be finished before the July 31st deadline (assuming no further issues), which is required under the company's approved rate settlement for an $85.1M mid-year rate increase to recover no more than $514M of construction costs plus AFUDC. Discussions with surety bond providers Zurich and Liberty are set to begin next week, with management expecting several meetings to arrive at a mutual understanding of the level of coverage to be provided under the bonds' maximum $145.6M cap. The latest cost estimate, including AFUDC, is $620-$655M, or $106-$141M above the authorized level. As a reminder, should the plant's in-service date look delayed beyond July 31, the company would continue to record AFUDC and would face several choices:

1. It could be required to renegotiate its prior rate settlement to seek a new deadline before which the company may place the plant in rates. We wouldn't anticipate much of a problem renegotiating the deadline for a potential delay as long as any excess cost (including extra AFUDC) above the approved $514M is covered by the surety bonds.

2. Alternatively, POR could seek a special accounting order from regulators to defer depreciation and other costs through to the next general ratecase, although this looks like a tougher route to us.

3. In the event of delays and given no other choices, POR would consider a full rate filing earlier than expected (the current plan is to wait until late 2018).

4. If there are costs above the $514M uncovered by the surety bonds, we are inclined to believe that POR would stand a fair chance of full recovery for the excess amounts (of capital and on capital, including equity) in the next ratecase given that regulators had already approved the process by which the defaulted contractor Abienza was chosen for the project. This process included an independent third-party scored review of some 10 bids. Without prejudging the outcome of any full review of the facts, we emphasize that a fundamental tenet of the regulatory compact is that any *prudent* use of the shareholder's balance sheet rightfully deserves full recovery of and on all capital employed, including equity on the books that supports the company's credit rating and cost of debt.

Renewables legislation passes – over $1B potential opportunity for POR

On Wednesday and Thursday, Oregon's proposed renewables legislation (HB 4036) was passed by both the state House and Senate during the current abbreviated session that ends on March 4. The Governor has been supportive and is expected to sign the bill into law shortly. Among other provisions, HB4036 proposes to raise the state's renewable portfolio standard (RPS) to 50% by 2040 and eliminate coal by wire by 2030 (Colstrip imports by 2035). With passage, we expect the currently suspended effort to achieve similar objectives through two separate ballot initiatives to be permanently quashed.

As we've noted previously, the law could open up more than $1B of opportunity for new ratebased renewables and supporting peaking generation for POR over the next 15 years as up to another ~5 or 6 Tucannon-sized wind farms are likely necessary to fulfill the requirements of the new law by 2040 (with one required by

2020). While we expect a material portion of this development to occur within POR's ratebase, we would also expect independent power producers in the region to highlight the problems with Carty in their effort to argue in favor of PPAs.

PPL Corp.

Top Three Takeaways:

(1) *Since its 1/15 disclosures management layered in additional 2018 hedges and is now 41% hedged at an average rate of $1.56 vs 20% at $1.60; the 2016 hedge rate declined to $1.54 from $1.56 previously. This drove the foreign currency sensitivity down and management does not intend to pursue further restrikes until after the June UK referendum (Brexit). Shares of PPL continue to exhibit daily volatility around the movement in the foreign exchange rate but we see the discount for shares as unwarranted.*

(2) *While timing has not been determined yet, PPL increasingly intends to host an Analyst Day where it hopes to not help explain the value of the UK business better to US investors but also highlight the earnings power of the US utilities which can be overlooked. For example, despite another year of contracting load growth in KY (-1.4% weather normalized) and unfavorable weather (-2.3% unadjusted decline in sales), the subsidiary earned a 10.6% ROE - a significant improvement from historical levels.*

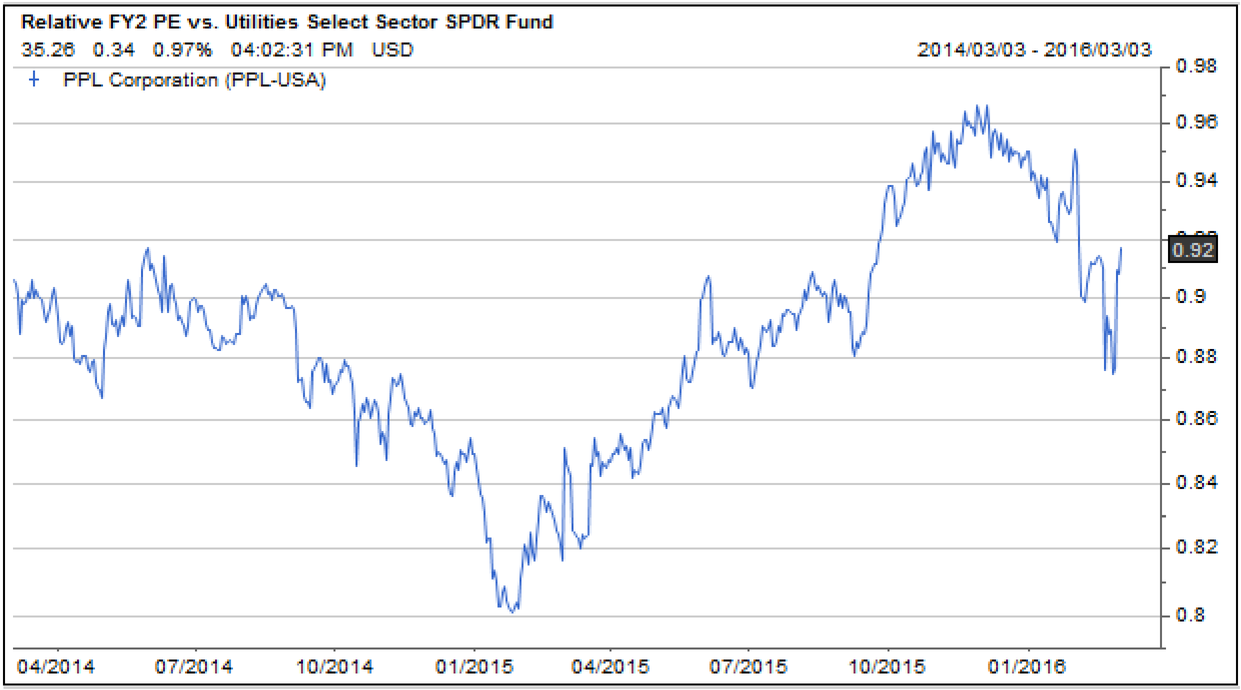
(3) *Even without Clean Power Plan spending in Kentucky, management believes there could be incremental capex opportunities available in the state outside of environmental. Specifically mentioned were a potential step-up in spending at the gas business, C&I solar, and other T&D spending that it could accelerate after the extension of bonus depreciation.*

PPL hedges aggressively amidst "Brexit" concerns: In the face of growing speculation and uncertainty about Britain's membership in the European Union, PPL layered in more hedges in 2018 by executing on its re-strike plan. The company outlined in a presentation their expected percentage of foreign currency hedged for 2016, 2017, and 2018 at 95%, 89%, and 41%, respectively. No additional hedging is expected before the June referendum and management still sees latitude to bring the 2018 hedging up to 50% based upon the conservatism in its earnings guidance elaborated on the 4Q15 call. Management does not expect the company's operations in the UK to be affected by the referendum; however, volatility in currency markets may have an adverse effect on earnings.

With investors continuing to undervalue the firm, management increasingly considering an Analyst Day: PPL rallied in 2H15 and was trading at only a 4% discount in December but has steadily seen its discount expand again and was trading at a 12% discount last week. While we acknowledge that the foreign currency exchange rate is a headwind we believe shares should be trading at closer to an in-line multiple. We expect management to further emphasize the (1) the cash flow profile of the segment and how it could be valued higher on a dividend yield basis; (2) delta between its utility performance and peers; and (3) growth opportunities in the next rate regime. The Analyst Day would not just focus on the UK but also on how strong/visible the growth profile is domestically. We

have historically underestimated the earned ROEs in Kentucky but management has put together a strong track record of performance. Based on its historical pattern we still estimate that rate cases will be filed approximately every other year in KY but we would not be surprised to see management stay-out longer in PA.

Figure 14: PPL Relative FY2 P/E



Source: FactSet

More regulated spending potential in both PA and KY: This could be revealed in the Analyst Day potentially but management highlighted opportunities across the board - gas, solar, and T&D spending acceleration**.** Perhaps most interestingly was the discussion of gas growth in Kentucky as management has not historically focused there. We would not be surprised to see management ultimately explore gas reserves in ratebase in Kentucky, particularly if it does add more gas capacity at the electric utility. The current plans are not based on the Clean Power Plan but the deferred combined cycle could be added back in the KY plan in 2020-2022, recoverable via the existing environmental rider. Our conversation did not touch upon the Compass transmission project but if management is successful on even portions of the line it would form a solid foundation for growth beyond the current EPS CAGR.

SCANA Corporation

With tax breaks and interest savings, even the fixed cost option looks inexpensive

Facing a choice in 6-8 weeks between the $7.6B fixed price option from Westinghouse and the $7.1B variable priced amended contract, management noted that actual interest costs are about 1% lower (~5% vs orig est of 6%) than those embedded in the original $6.8B cost estimate for the plant. Furthermore, SCG expects to book more than double the original ~$50M-$60M estimate for annual production tax credits over the first 8 years of operation. This is because there are fewer AP 1000 plants under construction to share in the 6-GW PTC pool than originally estimated. The combination of the two is expected to reduce the cost of the plant (vs original estimates) by nearly $800M, which would result in a final cost of even the fixed price option at nearly the same as the original $6.8B.

We also get the impression that both Staff and investors are leaning toward taking the fixed price option at this (early) time, which would require Westinghouse to pay for any amounts over the fixed contract if taken. The contract is guaranteed by parent Toshiba but is now also backed up by a surety bond as a result of Toshiba's triggering of bond metrics. Furthermore, SCG has previously discussed their ownership of intellectual property (chiefly design documents and source codes) in order to be able to transfer them to a new contractor if necessary. However, the likely "new" contractor that would replace Westinghouse if necessary is Fluor.

Once an option is chosen, the next step is to seek regulatory approval, although management notes that the bar to disallow costs is high, with the burden of proof of imprudence on the opposing parties.

Southern Company

Working behind the meter with the PowerSecure acquisition

The recent $431M acquisition of PowerSecure sits directly underneath the corporate parent and is not part of Southern Power. The goal of the purchase is to rapidly develop a "behind the meter" services business for large commercial, industrial, and government (especially DoD) entities with a need for reliable on-site backup and primary power, such as data centers, hospitals, grocery storage and retail, etc. The business is virtually 100% fee-based, with SO intending to focus on expanding the customer base and extending contract lengths from the current 18 months. PowerSecure has not been focused on distributed energy systems (as EIX's Edison Energy Group will likely include as a core strength).

Kemper and Vogtle progress – no change from 4Q earnings call

Management emphasized that at this stage of sunk costs, finishing the Kemper IGCC plant is by far preferable to shutting the project off. Repairs to the refractory tubes are closer to completion. With the remaining ratecase to be filed once the plant is in service, we note the more favorable composition of the Miss Public Service Commission (PSC) since last year's election that defeated anti-Kemper advocate Blanton. Management estimates that after a 15% rate increase in December (plus refund checks), another sizeable rate increase will be necessary once in-service, although this could be offset with tax credits and grants. Recall that SO announced further delays to Aug 31, 2016 (from June 30) for the Kemper IGCC plant, with an additional $110M of unrecoverable costs. Repairs and modifications to the gasifier refractory lining continue, and management also cites ongoing start-up and commissioning challenges.

Southern is in discussions with the IRS about whether the cost of the Kemper IGCC plant would qualify for the Section 174 Research and Experimentation (R&E) tax deduction. Mississippi Power can recognize the tax deductions as dollars are spent on eligible investments and the company has so far taken $3Bn of deductions with a $1Bn reserve. While uncertain, management indicated that this could offset the loss of the Phase II credits and would not require the same strict standards about the operations of the carbon capture system as the Phase II credit. If unsuccessful in this deduction SO believes bonus depreciation would offer a decent hedge that allows the ability to deduct a solid portion of the plant.

Also included in the tax extenders bill is the opportunity for reallocation of the US Department of Energy's $160Mn grants from the Clean Coal Power Initiative (CCPI) that were previously allocated to projects that were ultimately not completed. A primary beneficiary of this provision could be Kemper, with Mississippi Public Service Commissioner Brandon Presley commenting that $80-$100Mn could be allocated towards Mississippi Power ratepayers. SO has pointed towards the lower-end of the range simply assuming that the $160Mn of available funds could be split evenly between Kemper and another eligible project.

For the Vogtle new nuclear construction project, Georgia regulators ordered a review of the recent Vogtle agreement with the intention of reaching a settlement with the company within six months to declare prior and planned costs and schedule as prudent.

SunPower

P-Series capex is ~10c/W, which is significantly lower than many competitors, due to the low-tech nature of the manufacturing, and the fact that the modco lines simply need to be upgraded to handle the P-series technology. SPWR sees this giving them a competitive edge, and will be critical to the company growing a larger presence in the emerging markets. From a capacity standpoint, mgmt stated that Fab 5 is ~4 years out, and got delayed a bit due to P-Series expansion.

Thematically, we remain broadly worried around a ramping of module capacity globally across all manufacturers – and implications for pricing. While better technologies should still see better margins – the profitability of the sector at large can still be pressured, particularly as mgmt builds into the next global 'peak year' of ~2018/19 as best we can tell.

Commercial will be a key market for the company, with strategic acquisitions placing them in a position to take greater share. On the equipment side, the introduction of the Helix system is expected to streamline the installation process. Mgmt stated that they are looking to make a strong push into commercial because the market is more akin to utility-scale from the standpoint that it is less prone to shifts in policy than residential.

While SPWR sees high demand for residential, they expect that the fight against the utilities, along with the decrease in battery costs, could position solar + storage at the residential level to make an important push in the coming years. However, the current battery costs render the market in many states immature currently, with HI being the only outlier here given the high power prices and ideal solar conditions. On the residential side, SPWR noted that they are looking to expand the digital sales business, as this is the lowest cost customer acquisition strategy. The company hired a former dell marketing executive in order to build this platform, which they expect will be where the market transitions to as customer awareness in residential solar along with the leading brands increases.

In relation to the several resi portfolios that have been put up for sale, SPWR mgmt expects that a private equity buyer could emerge, as the sellers are largely in need of liquidity, and this need to sell will likely drive returns for the buyer to the level that PE requires. Mgmt noted that they don't think there has been an acquisition yet because the various parties do not agree on the assumptions that go into the valuations, with residual value and discount rate assumptions the most contentious. SPWR noted that an 8% discount rate for the contracted portion makes sense in their view.

Mgmt recently closed its latest tax equity fund that the company expects will provide capacity through the end of 2016. Broadly, tax equity availability remains a key point of consternation for the residential solar sector, although players like SPWR and NEE have stated that they see plenty of demand to deploy capital by tax equity financiers in 2016. The opportunity to develop resi through 2016 without tax equity capital restrictions places SPWR at a competitive advantage vs. peers like SCTY and other smaller developers who live by their limited capital access to these sources.

Mgmt noted that their prior guidance didn't fully take into account the ITC extension, and while they have not yet changed their views on 2017 yet, they acknowledged that there could be some revisions in the coming quarterly reports.

The key here is that lead times are vastly different by segment, so gaining clarity on the utility scale space, where lead times are in the 1-3 year range, is not as immediate as residential, and to a lesser extent commercial. In SunPower's 4Q15 earnings presentation, the company provided its first view of development opportunities beyond the previous ITC cliff, emphasizing a more commercial weighted set into 2017, with 2018/19 shifting back towards a more Power Plant weighted development focus, as procurement activities appear tied to maximize the value of maximum ITC. All around, plans delineated at its Analyst Day to double EBITDA by 2020 and triple volumes to 4GW by 2019 appear on track (with ~half from P-Series) – boding well for its YieldCo subsidiary 8point3 Energy.

Among the key benefits from the ITC extension is a swing in development focus for both CAFD parent sponsors back to the US, rather than shifting abroad – and to EM – to source growth without the extension in 2017+ as previously outlined. New projects appear to be oriented across the Southern belt of the US – beyond the traditional Southwest market, with an emphasis on the Southeast. We emphasize the Infigen transaction complements SPWR's historic pipeline with projects oriented in the Southeast, providing access to much of this burgeoning market. That said, SPWR's relationship with Total gives it an advantage internationally, especially in the Middle East and Africa. While mgmt stated that they would focus on the US with the ITC extension, over 70% of SPWR's aggregate pipeline is located outside of the US, indicating the company's global reach and diversification aspirations.

Regarding SUNE's position, mgmt noted that they hope SUNE can turn the tide as they expect a SUNE liquidity crisis will further drag the market down. SPWR noted that the financial engineering, along with overly aggressive bidding for assets along with PPAs, led to SUNE's demise, but that SPWR can benefit from the downturn with assets and projects being reintroduced into the market, along with key talent, and even land rights up for grabs. Bases on SPWR's analysis, SUNE won bids on projects at 0 NPVs and negative IRRs. Mgmt noted that the counterparties are now more concerned with counterparty risk than they previously were, giving SPWR an advantage. SUNE's situation is bringing talent along with assets into the market, with SPWR noting that they could look to take advantage of the situation on both levels given their growth prospects along with strong liquidity position.

CAFD is targeting an 80% payout ratio, but is adamant on not allowing the payout to reach incrementally higher than 80%. Mgmt. stated that with the ROFO list alone they can hit the dividend targets, and would actually need to scale the payout ratio down if they drop down the entire ROFO list. As a result of FSLR's planned Stateline sale to CAFD in 2017, SPWR mgmt stated that they don't expect huge sales in 2017, as they don't need to sell to CAFD to hit the growth targets.

Talen Energy Corp

Top Three Takeaways:

(1) *Capital allocation is a top focus and while management sees significant value in repurchasing its longer-dated bonds trading at material discounts; its preference is to execute on organic growth/M&A if the return/return profile is comparable.*

(2) *Management is still confident in the unregulated markets and expects favorable outcomes in the pending Ohio regulatory proceeds for PPAs and Supreme Court energy cases.*

(3) *Talen continues to evaluate its asset-level cost structure and believes the O&M reductions disclosed lately (ex-synergies) are sustainable. Without discussing specifics, management does see a path to further costs reductions at Susquehanna in accordance with the NEI industry-wide initiative but sees the nuclear asset as well positioned for today's market environment even with its current cost profile.*

Preference is for growth but repurchasing debt is very compelling: The number one topic for Talen continues to be capital allocation and how management decides to utilize the proceeds from its asset divestitures ($1,220Mn) disclosed in 2015 as well as organic free cash flow generated in 2016E ($350Mn midpoint pre- $108Mn growth capex). On the 4Q15 call last week Talen disclosed that it has already repaid $500Mn of revolver borrowings in February and at a minimum intends to retire $396Mn of maturing debt obligations in 2016. We present our preliminary cash flow analysis below. While Talen's first preference is seemingly to execute on growth opportunities, it sees the return profile of repurchasing its own debt as very compelling as it can effectively 'lock-in' an IRR on the transaction. With 2019+ debt trading at material discounts (20%+ as of the earnings call) it sees an attractive return profile but management is mindful of the need to balance the return profile with investors' desire for near-term liquidity. Although Talen was not involved in the Engie transaction, management comments that it still sees a robust opportunity set of potential power assets in the market. For example, Talen estimates that ~20GW of capacity trades hands on average annually in the power markets.

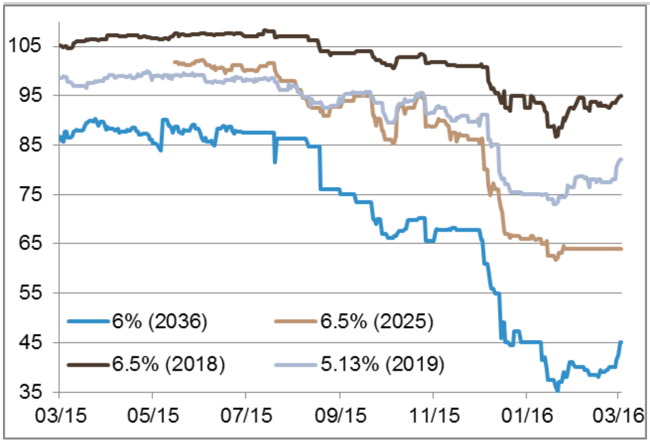
If it is able to achieve the same/similar returns from executing on M&A/organic expansions vs paying down debt, we believe Talen will pursue the growth avenue given the qualitative attributes (asset/fuel diversification, etc.)

Figure 15: Talen Cash Flow Analysis

Cash Flow Analysis ($Mn)	**2016E**
YE15 Unrestricted Cash Balance	141
Release of Restricted Cash	55
Divestiture Proceeds	1,220
2016E FCF	249
Less: TSA Costs	(25)
Less: Feb Revolver Repayment	(500)
Less: Jan Ironwood Redemption	(41)
Capital Available for Allocation	**1,099**
Less: 2016 Debt Maturities	(355)
Less: Minimum Cash Target	(200)
Remaining Available for Allocation	**544**
Commited 2016 Debt Reduction	**(896)**
Total Potential Debt Reduction in 2016	**(1,440)**

Source: Company Filings and UBS Estimates

Figure 16: Talen Bond Trading Values



Source: FactSet

Secured debt could help facilitate liabilities management program: Talen has been exploring whether it should add more secured asset-level debt to some of its facilities in order to create capacity to reduce corporate level obligations. Management is carefully weighing its options as it sees value in its current flexible capital structure which does not have significant covenants currently.

Limited secured debt makes corporate level M&A easier to execute.

Best Harquahala risk/reward likely involves finding a local solution: Management believes the best risk/reward is in finding a local solution whether it can sell the plant to a local utility or enter 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. As a reminder, Arizona Public Service has an RFP set for March but the timeline could be protracted

The APS RFP will be an important process to watch for TLN.

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.

Carefully expanding MACH Gen: Another growth avenue discussed by management was potential attractively priced uprates for its Athens/Millennium plants, collectively ~80-85MWs. In-service of the Constitution pipeline has been delayed to late-2016/early-2017 (we say 1H17) based on what management has observed but it still expects improved spreads for its Athens plant in New York. Talen has also observed a reduction in electric transmission constraints around the Athens plant as flows have been reduced; however, this could relate to the below-average weather recently.

Looking at the markets: In its Pennsylvania footprint management believes drilling is slowing and that natural gas pricing should stabilize but does not anticipate a quick commodity recovery. Following a strong operational year at Susquehanna, management is confident that it can further improve the cost structure of the 2.3GW nuclear asset as part of the broader industry-wide push to reduce nuclear costs.

TLN sees its nuclear cost structure as competitive and anticipates improvements.

Across its fleet none of Talen's eastern assets are generating losses although the economics of the ERCOT fleet are more challenged. Management believes that there could be further asset rationalization in the TX market in 2017-2018 as generators get closer to facing environmental liabilities. Additionally potential reforms to the ORDC could help price formation going forward if approved by the Public Utilities Commission of Texas (PUCT). Finding a way to monetize the money-losing Colstrip assets remains a priority but any transaction with a utility seemingly would still require local legislation to be passed.

In 2015 Talen made substantially all of the year's EBITDA in ERCOT in a ~10-day period this summer when there was above-average weather; FY15 adjusted EBITDA from the West was $56Mn but this also includes Colstrip.

Still confident in markets for the long term: Talen continues to believe that the Supreme Court and FERC will make the "right decision" when reviewing the facts of the relevant cases impacting the power markets such as the Maryland/New Jersey case and the Ohio PPA requests. Talen does not perceive a risk that there will be a broader push for re-regulation in its markets.

WEC Corporation

Peoples is already earning its allowed ROE

Management reports that Peoples Gas improved its earned ROE all the way from the prior record of ~5.5% to the fully authorized level of 9.05% for full-year 2015. Furthermore, the utility is on track for another 9.05% in 2016 as well. For WEC as a whole, interest savings from debt paydown boosts long-term earnings growth by about 1% within the 5%-7% guidance. *We look for management to continue to revise up its capex in an effort to offset the impacts of bonus depreciation.*

Exploring Canadian hydro imports to cut Carbon

Former Integrys utility Wisconsin Public Service (WPS) already has a few tranches of power contracted from Manitoba Hydro and WEC has discussed the possibility of importing more carbon free energy as part of a strategy to comply with stricter standards under the EPA's currently stayed Clean Power Plan. Regarding the possibility of participation in Allete Inc.'s Great Northern Transmission Line to Manitoba, this appears possible only through its 60% ownership stake in American Transmission Company (ATC). More specifically, ATC participates in a 50%/50% joint venture with Duke Energy (Duke ATC).

Riverside option neither selected yet nor in the forecast

Regarding the recent deal with Alliant Energy to allow WEC to buy into a maximum 200 MW of the planned 700-MW Riverside Energy Center, WEC emphasizes that this option has not yet been exercised nor is it part of the latest capital forecast. As a reciprocal part of the deal, Alliant is also allowed to invest in one of WPS's future generation projects as well.

Paying down corporate debt – to drive EPS growth

Management recently announced the results of its Dutch auction to pay down the ~6% legacy Integrys HoldCo debt. That resulted in roughly ~$100 mn of $270 Mn, part of a wider effect to reduce high-cost interest expense to achieve prospective EPS growth.

Westar Energy

Wind plants only -$0.02 dilutive while awaiting 2018 rate filing

With the next ratecase not until mid-2018 (for 2019 rates), management confirmed our estimate for only about $0.02 dilution from the recently acquired 280-MW Western Plains Wind Farm and 100 MW (50%) of the Kingman Wind Energy Center while the company collects PTCs in lieu of higher rates through 2019. The reason the company is constructing/contracting for the plants today is to lock in current low prices to dispatch <$20/MWh (competitive or even cheaper than coal).

Modest bonus depreciation hit reduces the ratebase growth forecast by ~50 bps

As published on the 4Q earnings call, the new ratebase forecast adds several new elements to the preliminary update provided in January (which had previously been updated for recent wind investments). It now includes both the impact of ramping transmission spending up to $250M/yr ($120M over the 5 year period), offset by a total $150M-$200M of bonus depreciation. It also includes an incremental $70M of pre-approved spend through Feb 2017 in this year's abbreviated ratecase for LaCygne, Wolf Creek, and other environmental ($50M of grid resiliency is already in the forecast). The new 5-year CAGR from 2015-2020 is 4.9% vs 5.5% for the prior 4-yr 2015-2019, but as we note below, we estimate this would increase to 5.2% with the addition of 100MW of wind from the option to purchase the half of the Kingman Energy Center from Nextera (see below for details).

Both the prior and new forecasts already include the recent acquisitions of the 280-MW Western Plains Wind Farm and 100 MW (50%) of the Kingman Wind Energy Center for a combined investment of about $600M (we estimate about $435M of ratebase).

2016 Guidance factors are slightly positive although no change to the range

WR announced the "finalization" of 2016 guidance on the 4Q call, unchanged from the preliminary $2.38-$2.53 vs UBSe $2.38 and cons $2.44 that was initiated a bit earlier than usual in November. Although some factors have changed (flat O&M instead of -2% cut, lower interest expense, higher depreciation, higher AFUDC, higher transmission), the net impact appears to be about +$0.02 vs preliminary guidance. The sales forecast for 2016 remains about 50 bps.

Xcel Energy

Confident on renewables to offset bonus depreciation

Public Service Co of Colorado will file a new Integrated Resource Plan (IRP) in May that will include the previously discussed $900M renewable plan for 600 MW of wind and 400 MW of solar by 2020. XEL's current $15.2B, 5-yr base capital plan

from 2016-2020 assumes that none of this is ratebased, although we note that Colorado already has a law on the books authorizing the utility to ratebase up to 25%. However, within the company's $17.7B "upside" capital plan, management assumes that 50% is ratebased (i.e., 300 MW of wind and 200 MW of solar).

In Minnesota, the latest Oct 2nd update to the Minnesota Integrated Resource Plan (IRP) includes (among other things) 800 MW of new wind and 400 MW of new solar by 2020. The $15.2B base capital plan assumes 25% of this will be ratebased (200 MW of wind and 100 MW of solar), while the $17.7B upside plan includes a 50% level (400 MW wind and 200 MW solar). Management notes the successful recent history of Northern States Power, which in recent years received approval to ratebase 2 of 4 wind plants there and then ratebased a third (Courtenay) when the independent developer experienced financial difficulties.

The company's latest forecast calls for 3.7% ratebase growth from 2015-2020 based on the $15.2B capital plan at the current earned ROE of 8.9%. However, this ramps up to 5.5% under the $17.7B upside plan and even further to 5.5%-6.0% with a 50 bps ROE improvement to 9.4% (this improvement is, in fact, targeted by 2018). Full earnings power in the upside case at $17.7B capital while earning an authorized 9.8% ROE would result in earnings growth above the target range of 4%-6%. More broadly, the incremental $2.5B in the upside plan includes the following:

- $300Mn ratebasing natural gas reserves
- $900Mn incremental Colorado renewables
- $300Mn grid modernization and AMI
- $300M "Steel for Fuel" – the acquisition of plants with expiring PPAs
- Majority of remainder is Minnesota – primarily renewables
- Transmission growth, although opportunities for competitive growth are currently limited

Ratebased gas initiative framework

Public Service Co of Colorado (PSCo) is working with Colorado regulators and Questar's Wexpro unit in Utah to get a broad framework approved for ratebasing natural gas reserves in order to reduce future price volatility and lock in the current low price environment for customers. The company intends to seek ratebased gas reserves (and pipelines) for 25% of Colorado gas utility and power generation requirements over 10 years at an estimates cost of about $500M (ratable to ~$300M for the first 5 years in the current capex plan). In contrast to the Wexpro I legacy reserve arrangement from 1981 at a 19.76% ROE, XEL's PSCo unit would be limited to an ROE tied +/-100bp vs. their Colorado authorized ROE. Colorado regulators have 240 days to reach a decision on the regulatory framework. We sense this is the upside in the capex with the relative least likelihood.

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. Valuation for IPPs and competitive integrated utilities is based on a sum-of-the-parts analysis.

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Neutral	FSR is between -6% and 6% of the MRA.	39%	28%
Sell	FSR is > 6% below the MRA.	12%	22%
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 31 December 2015.
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Abengoa Yield PLC[5, 16]	ABY.O	Not Rated	N/A	US$16.75	03 Mar 2016
AES Corporation[16]	AES.N	Neutral	N/A	US$10.45	03 Mar 2016
ALLETE[16]	ALE.N	Not Rated	N/A	US$54.00	03 Mar 2016
Alliant Energy Corp.[16]	LNT.N	Not Rated	N/A	US$68.68	03 Mar 2016
Ameren Corp.[16]	AEE.N	Neutral	N/A	US$47.00	03 Mar 2016
American Electric Power, Inc.[2, 4, 6a, 6b, 7, 16]	AEP.N	Buy	N/A	US$61.77	03 Mar 2016
Avista Corp[4, 6c, 7, 16]	AVA.N	Neutral	N/A	US$38.03	03 Mar 2016
Black Hills Corp.[6b, 7, 16]	BKH.N	Not Rated	N/A	US$55.82	03 Mar 2016
Calpine Corporation[4, 6a, 7, 16]	CPN.N	Buy	N/A	US$13.88	03 Mar 2016
CenterPoint Energy Inc.[5, 16]	CNP.N	Not Rated	N/A	US$18.78	03 Mar 2016
Chesapeake Utilities Corp.[16]	CPK.N	Not Rated	N/A	US$58.23	03 Mar 2016
CMS Energy Corporation[16]	CMS.N	Neutral	N/A	US$39.69	03 Mar 2016
Consolidated Edison[2, 4, 5, 6a, 16]	ED.N	Sell	N/A	US$70.63	03 Mar 2016
Covanta Holding Corp.[16]	CVA.N	Not Rated	N/A	US$15.11	03 Mar 2016
Dominion Midstream Partners LP[16]	DM.N	Buy	N/A	US$33.54	03 Mar 2016
Dominion Resources[2, 4, 5, 6a, 6b, 6c, 7, 16]	D.N	Neutral	N/A	US$69.99	03 Mar 2016
DTE Energy Co.[2, 4, 6a, 7, 16]	DTE.N	Buy	N/A	US$84.01	03 Mar 2016
Duke Energy[2, 4, 5, 6a, 6c, 7, 16]	DUK.N	Buy	N/A	US$74.33	03 Mar 2016
Dynegy, Inc.[4, 6a, 7, 16]	DYN.N	Buy	N/A	US$11.60	03 Mar 2016
Edison International[4, 6a, 7, 16]	EIX.N	Buy	N/A	US$67.42	03 Mar 2016
El Paso Electric Co.[16]	EE.N	Not Rated	N/A	US$41.05	03 Mar 2016
Emera Incorporated	EMA.TO	Not Rated	N/A	C$45.89	03 Mar 2016
Empire District Electric Company[16, 19]	EDE.N	Neutral (CBE)	N/A	US$33.08	03 Mar 2016
Entergy Corp.[16]	ETR.N	Sell	N/A	US$73.14	03 Mar 2016
Eversource Energy[16]	ES.N	Neutral	N/A	US$54.63	03 Mar 2016
Exelon Corp.[4, 6a, 7, 16]	EXC.N	Neutral	N/A	US$33.08	03 Mar 2016
First Solar Inc[16]	FSLR.O	Neutral	N/A	US$69.71	03 Mar 2016
FirstEnergy Corp.[7, 16]	FE.N	Neutral	N/A	US$33.98	03 Mar 2016
Hannon Armstrong Sustainable Infrastruct[13, 16]	HASI.N	Buy	N/A	US$18.12	03 Mar 2016
Hawaiian Electric Industries[16]	HE.N	Not Rated	N/A	US$30.11	03 Mar 2016
Idacorp, Inc.[16]	IDA.N	Not Rated	N/A	US$71.44	03 Mar 2016
Laclede Group Inc.[16]	LG.N	Not Rated	N/A	US$65.05	03 Mar 2016
MGE Energy Inc.[16]	MGEE.O	Not Rated	N/A	US$49.24	03 Mar 2016
New Jersey Resources Corp[16]	NJR.N	Not Rated	N/A	US$34.37	03 Mar 2016
NextEra Energy[4, 5, 6a, 6c, 7, 16]	NEE.N	Buy	N/A	US$111.62	03 Mar 2016
NextEra Energy Partners LP[2, 4, 5, 6a, 16]	NEP.N	Neutral	N/A	US$25.61	03 Mar 2016
NorthWestern Corp[6b, 7, 16]	NWE.N	Not Rated	N/A	US$60.06	03 Mar 2016
NRG Energy Inc.[7, 16]	NRG.N	Buy	N/A	US$12.52	03 Mar 2016
NRG Yield[16]	NYLDa.N	Buy	N/A	US$13.11	03 Mar 2016
OGE Energy Corp[6a, 16]	OGE.N	Not Rated	N/A	US$26.05	03 Mar 2016
Otter Tail Corporation[16]	OTTR.O	Not Rated	N/A	US$27.10	03 Mar 2016

Company Name	Reuters	12-month rating	Short-term rating	Price	Price date
PG&E Corporation[16]	PCG.N	Neutral	N/A	US$56.29	03 Mar 2016
Pinnacle West Capital Co.[6a, 16]	PNW.N	Neutral	N/A	US$68.48	03 Mar 2016
PNM Resources Inc.[16]	PNM.N	Not Rated	N/A	US$32.43	03 Mar 2016
Portland General Electric Company[16]	POR.N	Buy	N/A	US$38.18	03 Mar 2016
PPL Corporation[2, 4, 5, 6a, 6c, 7, 16]	PPL.N	Buy	N/A	US$35.26	03 Mar 2016
Public Service Enterprise Group[16]	PEG.N	Neutral	N/A	US$43.86	03 Mar 2016
SCANA Corp.[2, 4, 6a, 7, 16]	SCG.N	Neutral	N/A	US$65.08	03 Mar 2016
Sempra Energy[2, 4, 5, 6a, 7, 16, 18]	SRE.N	Buy	N/A	US$98.56	03 Mar 2016
South Jersey Industries[16]	SJI.N	Not Rated	N/A	US$25.91	03 Mar 2016
Southern Company[2, 4, 5, 6a, 6c, 7, 16]	SO.N	Sell	N/A	US$48.19	03 Mar 2016
SunEdison Inc.[5, 13, 16]	SUNE.N	Sell	N/A	US$1.52	03 Mar 2016
SunPower Corp[16]	SPWR.O	Neutral	N/A	US$23.97	03 Mar 2016
Talen Energy Corp[4, 5, 6a, 16]	TLN.N	Neutral	N/A	US$7.66	03 Mar 2016
TransAlta Corporation[16]	TA.TO	Not Rated	N/A	C$6.01	03 Mar 2016
TransAlta Renewables Inc	RNW.TO	Not Rated	N/A	C$11.40	03 Mar 2016
Vectren Corp[16]	VVC.N	Not Rated	N/A	US$45.98	03 Mar 2016
WEC Energy Group Inc.[16]	WEC.N	Sell	N/A	US$56.47	03 Mar 2016
Westar Energy, Inc.[6a, 16]	WR.N	Neutral	N/A	US$43.15	03 Mar 2016
Xcel Energy Inc.[7, 16]	XEL.N	Sell	N/A	US$39.60	03 Mar 2016

Source: UBS. All prices as of local market close.
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