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What the Elections Holds for Utilities

Equities

Americas
Electric Utilities

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Ahead of mid-term elections, we look at what could come for utilities & IPPs

We generally suspect elections will have only a modest impact, with a few key states and processes to watch for specific companies. While FL has garnered the most attention, federal PTC extension, complete changeover in AR PSC composition (along with a new governor), and progress on asset privatization in WI are worth noting. In MI, we see consistency to expand the RPS as largely ringing positive with either party. We see no real developments from a legislative perspective should Republicans take the Senate, with the real focus mostly on corresponding state-level commission appointees resulting from new governors. Net-net, we suspect renewables could perform well late this year given PTCs, whilst state elections are largely a risk for the remainder of utilities

Florida risk is real – but not to the extent Street has baked in

Given the possibility of slower spending and ratebase growth for NEE, we see the neck-in-neck Florida race as the most important to watch this November, albeit already heavily previewed by the Street (with shares of NEE in particular having under-performed; we're less convinced DUK and TE have reflected much concern). For NEE, we look beyond 2016 where mgmt could revise its 5-7% EPS CAGR from 2012-2016 as we assume that FP&L will file a rate case in 2016 (FP&L remains in a rate stay out through 2016). NEE is currently weighing a decision on whether to file a rate case in late 2015/early 2016 for Jan 2017 implementation. In the event of a Crist win, the company may attempt to avoid a filing with cuts to both capital and operating spending in an effort to preserve ROEs (albeit at a slower investment and earnings growth rate) through the duration of his term. We emphasize that a Crist term this time around would be quite different from his previous term as Governor given a Republican-controlled state legislature. It also very unlikely he would be able to incur meaningful change in PSC composition given that he will be forced to make his replacement choices from a list of nominees already composed by Governor Scott and largely acceptable to the state's utilities and investors.

Federal PTCs likely to be extended, in our view – big benefit to wind outlook

We continue to see a great deal of optimism from various industry stakeholders for the extension of production tax credits (PTC) through an extenders bill, to include the 2.3 cents per kWh PTC for wind. In our opinion, an extension is more likely to be a part of a broader package post-election season, albeit after negotiation in the Senate for the recently introduced HR 5559, or the 'Bridge to a Clean Energy Future Act of 2014'. It is unlikely that a broad package would pass with just the PTC component dropped. The legislation would extend the PTC, and the option to choose an ITC in lieu of the PTC, through 2016 (effectively 2018 with 2-year latitude to complete projects qualified as starting by year-end '16). However, there is some possibility that the extenders get delayed if the GOP wins the Senate, as Republican Senators may push instead for incorporating clauses from the Jobs for America Act.

PA worth watching for future round of state NO_x regs – more coal retirements?

Among smaller issues to watch, we suspect the election outcome in PA will determine the stringency of forthcoming issuance of RACT regs for NO_x. This is likely to determine the fate of plants in the state, including PPL's Bruner Island plant and even potentially NRG (GenOn's) Seward plant, both of which do not presently have SCRs installed; the balance of the states' larger coal units already have them. Under a less intensive rule implementation, future regs could simply require companies run *existing* equipment, however, a more stringent requirement could yet require installs of SCRs on all coal plants to meet state regs (a seemingly real threat, with Democrats in the lead).

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What to Follow into this Fall's Elections?

While largely *not* the biggest of deals for most utilities, we emphasize key races in FL, and WI could impact names like **DUK/NEE/TE** in FL, as well as **WEC** in WI. Meanwhile, we see Federal PTC extensions during lame duck in ~December could potentially prove a meaningful positive for renewable developers like **NEE** (more than offsetting the Crist risk embedded in shares in our view). Elsewhere, we see the outcome of new governor in AR along with an entirely new appointed bench of commissioners as a real wildcard (particularly given its recent low authorized ROE and amidst efforts to improve structural lag by Entergy in the state). We suspect **ETR** and **AEP** could oscillate around these developments, with AEP poised to seek to add Turk into ratebase once again (with a fresh commission to hear the issue).

In the Northeast, we see **ConEd** as poised to do well on the back of the re-election of Gov Cuomo in NY, with the administration poised to execute and announce on a potential raft of energy policy changes under the new term. We emphasize that while nominally much of the focus in New York is distributed in nature, we see ConEd as meaningfully participating in the build (along with **PSEG** too should it opt to participate through its Long Island subsidiary).

In New England, we suspect migration beyond the elections will enable for the NESCOE process once more to focus on new infrastructure development, although likely with a heavy tilt towards transmission solutions under RFP. This appears to be a key opportunity for **NU** to press not just its Northern Pas project, but potential other avenues for development, including an expedited timeline for its Greater Boston reliability projects. The risk around NESCOE into 2015 is the extent to which other projects (such as Blackstone's VT project) are able to compete.

What's among the best tactical opportunities on the back of this election note? <u>We see NEE as increasingly our top long-term pick</u>, seeing the continued focus on the election, coupled with real updates around long-term renewables (and guidance) coming late this year or early next as more than offsetting this concern. We emphasize the forthcoming 'election risk' is among the most heavily previewed – and see opportunity for a rally in shares either way, particularly in the case of a Republican win. Meanwhile, updates delineating accelerated NEP growth could help shares around 3Q results following the election (although full 2016 guidance update remains more of a ~2015 event, awaiting PTC outlook).

State by State Mid-Term Run-Down

We include a brief summary of our views on each important state below.

Federal PTC extension (wind subsidy) – In our opinion, an extension is more likely to be a part of a broader package post-election season, albeit after negotiation in the Senate for the recently introduced HR 5559. However, there is some possibility that the extenders get delayed if the GOP wins the Senate, as Republican Senators may push instead for incorporating clauses from the Jobs for America Act.

Florida – It's a close race, but a Crist victory would not be like his previous term as the Republican legislature would be distinctively combative toward him and any replacement nominees for the FPSC would come from a list already chosen by Governor Scott. Nevertheless, a Crist victory would likely lead to a slowdown in capital investment for the utilities, although there might be some increased interest in ratebased solar. Duke's deal with Crystal River/ new generation also bears watching. *Investors have watched this race the closest of any in the country – with expectations already meaningfully compressed vs. other jurisdictions (particularly for NEE vs. DUK or TE).*

Wisconsin - Gubernatorial polls are tight, but if the incumbent Republican Scott Walker retains his position as Governor, we think privatization initiatives will go ahead. However, we think the plans may be shelved in case the Democratic candidate Mary Burke wins.

Arizona - Republican primaries in August already effectively decided the outcome of most general election races, including the two new commissioners at the ACC. Expect constructive discussions around net metering and rate design through 2015 leading up to APS's mid-2016 ratecase filing.

Ohio – Gov Kasich's seat appears safe with a 20%+ lead and we expect his priorities to remain focussed on economic growth and jobs. This could translate to support for FE's and AEP's PPA requests, if only for Conesville and Sammis, perhaps at lower margins than implied by the utilities proposals.

Arkansas – See ETR and AEP as both poised to see a new governor, along with an entirely new bench on the commission.

Kansas – It's a tight race but Democratic challenger Paul Davis is a moderate Democrat in a very red state, so we wouldn't expect too much rollback of Governor Brownback's pro-business tax policies.

Michigan – It's close between Governor Snyder and Democratic challenger Mark Schauer, but no matter who wins, we still expect a higher renewable standard and new rate design that favors large industrial and commercial customers. The legislature is expected to take up a new energy package next year that could also eliminate retail shopping altogether and lower industrial rates further in support of economic growth. We believe that concerns that Chairman Quackenbush might leave the PSC under Schauer are unfounded. Could Michigan be set to turn the screws to the WEC-TEG merger?

New York – with Cuomo enjoying a strong lead, the question is what new policies will be unveiled in his latest term. We suspect a reinvigorated pushed towards distributed investments, as well as transmission too. ED is likely to continue to benefit from NYPSC advocacy for increased distribution resource dispatch infrastructure as well.

Massachusetts, Connecticut, RI, New Hampshire – With no incumbents running in either Mass or RI, we see NESCOE's RFP delayed into next year, at least. The race in CT is tight, with the Republican challenger Tom Foley having said little regarding his energy policy vs the generally forward-looking policies of the incumbent. In MA, the race is also tight, with a reduced emphasis on expensive renewable contracts. New Hampshire's race isn't close, with Governor Hassan enjoying a healthy 10 point lead.

Where do the races stand today?

Figure 1: Summary who's-who in the 2014 Governors Races

2014 Governors Races				
Likely Democrats	Leans Dem.	Toss-Up	Leans Rep.	Likely Republican
MD: Open	NH: Hassan (D)	AK: Parnell (R)	AZ: Open (R)	ID: Otter (R)
OR: Kizhaber	OR: Kitzhaber (D)	CO: Hickenlooper (D)	AR: Open (D)	IA: Brandstad (R)
PA: Corbett (R)		CT: Malloy (D)		NE: Open (R)
		FL: Scott (R)		NM: Martinez (R)
		GA: Deal (R)		OK: Fallin (R)
		HI: Open (D)		SC: Halley (R)
		IL: Quinn (D)		TX: Open (R)
		KS: Brownback (R)		
		ME: LePage (R)		
		MA: Open (D)		
		MI: Snyder (R)		
		RI: Open (D)		
		WI: Walker (R)		
Safe Democrat Races			Safe Republican Races	
CA: Brown (D)			AL: Bentley (R)	NV: Sandoval (R)
NY: Cuomo (D)			OH: Kasich (R)	SD: Daugaard (R)
			TN: Haslam (R)	WY: Mead (R)

Source: Real Clear Politics

Florida

So what would a Crist election mean for NextEra?

Polls remain neck-in-neck for the Governor's race with Scott vs prior Governor Crist at dead-even 44% each. Despite pervasive Street concerns over the subject, we emphasize a Crist win would most likely to take the form of a slow-down in capital spend for Nextera Energy (aside the ratebase gas reserves proposal) as the company seeks to moderate inflation trends on consumers. Given its rate stayout through 2016, we see more limited political influence at least initially.

We emphasize that a Crist term this time around would be quite different from his previous time as Governor given a very hostile Republican state legislature.

We also see timing of any Florida regulatory actions as key, before year end, and without influence of the new election dynamic. Specifically, we're focused on its gas ratebase proposal, which had always been anticipated to be approved before year end anyway. Broadly, we were surprised to see NEE as the most negatively affected by election sentiment in the group. Duke Energy arguably has been spared despite potentially greater regulatory risk, with a rate freeze expiring in 2016 and the recent expensive extended cold shutdown of CR3. TE's current rate deal extends to 2018 and should be fairly insulated from any election effect.

We emphasize that a Crist term this time around would be quite different from his previous time as Governor given a very hostile Republican state legislature that will likely be fighting him fiercely on other "bigger" subjects, such as Medicaid. As we note below, it is very unlikely he would be able to do serious damage to the PSC given that he will be forced to make his replacement choices from a list of nominees already composed by Governor Scott and largely acceptable to the state's utilities and investors.

A planned slowdown for NEE if Crist wins

As we discussed in **our previous note** following the Democratic primary, a victory by Democrat Crist over incumbent Governor Scott (R) will be perceived negatively for NextEra's Florida Power & Light (FP&L) and TECO's local utilities given previous interactions with the regulated entities. It does not appear to be a secret that the business community is more supportive of Scott but the potential impact of Crist winning is an unknown.

Utilities are likely hoping that Governor Scott's record on the economy wins out with voters…

Gubernatorial certainty will be key as we look beyond 2016 where management could revise its 5-7% EPS CAGR from 2012-2016 as we assume that FP&L will file a rate case in 2016 (FP&L remains in a rate stay out through 2016). NEE is currently weighing a decision on whether to file a rate case in late 2015/early 2016 for Jan 2017 implementation. In the event of a Crist win, the company may attempt to avoid a filing with cuts to both capital and operating spending in an effort to preserve ROEs (albeit at a slower investment and earnings growth rate) through the duration of his term.

…which will be key for NextEra's next rate case expected in 2016.

The company does not anticipate its next large generation need until the 2019/2020 timeframe so absent impacts from depreciation studies or utility scale solar, we would not expect significant rate inflation and pushback from regulators.

Risk around Florida PSC appointments declining

With Commissioners Eduardo Balbis' and Julie Brown's terms expiring at the end of this year and the remaining three Commissioners having terms extending through 2016-2018, Governor Scott's nomination process has resulted in two nominations (state Rep. Jimmy Patronis and the reappointment of Brown) and five alternate candidates (David Murzin, Stuart Pollins, Jerry Fernandez, Patrick Sheehan, and Kevin Wiehle). Our impression is that none of the seven are objectionable to the state's utilities. This is important in that should Crist win the election, he may reject Scott's final picks, but may only replace them with the other candidates already approved by the Florida Public Service Commission Nominating Council unless he receives legislative approval for a new nominating process – unlikely to be given by a still deeply Republican legislature that is largely antipathetic to Crist's recent "conversion" to the Democratic party in December 2012. In any event, we believe that a silver lining of a Crist administration could come in the form of a stronger emphasis on (ratebase-eligible) solar initiatives that have been sidelined on economic concerns by Scott. Exposed companies include TE, NEE, and DUK.

Signs of a nuclear renaissance?

Southern Company spent much of their **2Q14 earnings call** discussing the possibility of new nuclear build in the early 2020s and NextEra could be following suit if the latest EPA standards force the state to further reduce carbon emissions. NextEra is closely watching SCANA and Southern's progress on their respective projects and given the long lead-time ahead of nuclear development, we would not be surprised to hear management announce its intensions sooner rather than later with respect to its Turkey Point Units 6 & 7 (collectively 2.2GW). FP&L received approval from the Florida Siting Board in May 2014 for the two units and the 2009 application is still pending with the Nuclear Regulatory Commission (NRC). Late in August the NRC voted to end the moratorium on issuing new plant licenses and the Company is optimistic that it can receive its licenses in 2017. Duke cancelled the EPC contract for the construction of the two-unit Levy plant, but has kept in the NRC's queue for a construction and operating license (COL) as it maintains the

Serious Southern nuclear discussions could be kicked off in the next few years as sixty year license expirations loom.

option to build (but not an obligation). A decision on the COL should come by 2016. We note that the expensive troubled repairs and extended cold shutdown of CR3 may color state legislators' opinions regarding nuclear energy negatively, despite signs in recent years of a renewed interest as a long-term stabilizer of electricity rates.

The broader question from Southern and NextEra's contemplation of new nuclear is to what extent the country intends to replace nuclear units that will see their sixty-year licenses expiring in the late 2020/early 2030s. For example, Turkey Point Units 3 & 4 came online in 1972 & 1973. We see this issue becoming an increasingly popular topic in the next few years as the subject gains greater clarity with regulated utilities especially in the context of the latest EPA standards. The discussion of further extensions to eighty-year licenses remains a topic for discussion although retrofits and upgrades would be needed.

Don't look for much on the wind development side until PTC clarity

We don't expect management, nor its counterparties, will sign much in the way of further wind deals ahead of pending clarity of a further Production Tax Credit (PTC) clarity in the lame duck session later this year. While investor expectations continue to call for a further 2-year extension (pushing the effective date for project in-service to qualify into 2016, and some into 2017). As a reminder, management has already 1.8GW of backlog, out of the 500MW – 1.5GW range previously articulated at its last Analyst Day.

More solar soon? Utility-scale opportunities still lurk

Bias remains for utility scale over distributed generation.

NEE has appeared surprisingly confident in its outlook for up to ~400 MW of further utility-scale solar projects, with RFP developments likely to yield formal projects in 2H14. Not only could NEE be awarded some projects in the southeast, but could see further awards in California as well. While we expect the utility-scale market to continue to decelerate (amidst an increasingly competitive field of players), we think management will continue to de-emphasize opportunities in this segment.

Still not stoked on merits of DG – outside of C&I

Nextera management has also maintained its more sober view on the value proposition of distributed generation amidst a clear preference for large-scale C&I. We flag a clear reticence persists across a variety of companies from entering too aggressively the residential DG market.

Woodford Shale JV with PetroQuest driven by legislature and PSC interest; unlikely to be affected by a Crist victory

NEE has moved quickly on the gas rate base opportunity

Look for Marcellus focus on future ratebase opportunities potentially

In our NextEra Energy note, '**A Windy, Gassy, Yieldy Opportunity Set'**, we indicated that a gas E&P ratebase proposal was very likely in the near term. On June 25th, NextEra announced that Florida Power and Light (FP&L) had formed a joint venture with oil and gas producer PetroQuest Energy (PQ) to develop up to 38 natural gas production wells in the Woodford Shale play (Oklahoma). Under the agreement, PQ will develop and operate the wells, and FP&L will pay a share of the project's capital expenditures (FP&L's portion is estimated at approximately $191Mn NPV) in exchange for receiving natural gas. NextEra anticipates generating up to $107Mn in savings for its customers over the life of the project.

We expect the FL PSC to render its decision in late 2014/early 2015.

Arkansas

AEP waiting until after the Arkansas election to file ratecase for Turk

While the Republican candidate Asa Hutchinson currently has a strong 8% lead over Democrat Mike Ross, it's unlikely that any action on getting Turk into ratebase will take place in Arkansas until after the election there. In 2010, the Sierra Club was successful in getting Turk's CPCN overturned, and we believe that AEP is likely to wait until 2015 to file a ratecase for it. SWEPCo currently sells its portion of Turk's output into the market. Separately, we note Entergy's recent push for legislation in Arkansas to reduce regulatory lag in the state that could also benefit AEP (to a smaller extent).

ETR holding its breath on resetting the entire commission

Meanwhile, 2015 is a pivotal year for Entergy, emphasizing a rare opportunity to both engage with an entirely-new commission as well as potentially broach legislative change in the state to improve rate recovery constructs (akin to AEE's efforts to reach a comparable deal in MO). We see the appointment of an entirely new commission on the back of a new governor in the state as a key risk to watch. We expect Entergy to file for a rate case at some point in 2015, latest 2016, given its more meaningful lag – and need to file nearly consecutive cases. Given past pending cases in the state (and a relatively authorized ROE in its latest case), coupled with the past pending docket around Entergy's proposed spin of its transmission business, the company has had little occasion to engage the commission in recent years due to ex-parte considerations.

Wisconsin

Wisconsin asset sales – election results are key

What could happen to Wisconsin's "Crown Jewels"? Not much in 2014 it looks like.

Gubernatorial elections are due in Wisconsin in the first week of November. Polls are tight, but if the incumbent Republican Scott Walker retains his position as Governor, we think privatization initiatives will go ahead. However, we think the plans may be shelved in case the Democratic candidate Mary Burke wins.

Are there other interested parties in the assets? *Possibly*, but operator experience matters.

Nonetheless, should anything happen, it will only be in 2015 at the earliest. We do highlight however, that WEC has formed a 50/50 JV with MGE Energy (called State Energy Services) to evaluate potential bids for the possible sale of state-owned cogeneration facilities, should they happen. The possible portfolio which may be up for sale includes the 150-MW University of Wisconsin West Campus Cogeneration Facility built in 2005 for $190M as well as numerous other cogen plants located on state-owned property including prisons and other campuses. MGE Energy already owns 50% of the West Campus plant and operates it.

We expect that should the sale happen, it would probably be financed in a way similar to WEC's Power the Future, with a long-term fixed-ROE contracts outside of ratebase that could last 20 years or more (but with a lower ROE in the ~10% range). We also note that many of the plants have likely been out of environmental compliance and would almost certainly need significant scrubber upgrades. Conversion to gas is probably a non-starter too as the plants are used for steam heating as well as electricity. While there has been no official cost estimate, we note that at times, unofficial numbers have been thrown around in the press in the neighborhood of $200-$250M.

Ratebase opportunity could be worth up to ~$1/sh.

More specifically, the Wisconsin budget grants the Building Commission with the authority to sell or lease state buildings (albeit with restrictions), subject to the approval of the Joint Committee on Finance. Currently the state is still in the process of retaining an advisor to oversee the process but it does not appear that significant progress has been made recently although selecting an advisor is certainly a step in the right direction.

Additionally with competition for the assets among regional peers, a JV makes sense as it was always unclear if WEC could be awarded all of the investment, at best representing ~$0.06 in EPS as calculated below ($0.03 under a 50% JV). 'Ratebasing' these assets appears unlikely, but pre-arranged sales & PPA agreements back to the state will provide regulated-like returns. We look for more concrete details in the upcoming three-to-six months, as negotiation and RFP get under way.

Figure 2: Potential EPS from WI Privatization if Ratebased

Wisconsin Privation Potential EPS	
Capex ($Mn)	$250
WI ROE	10.40%
Midpoint WI Equity Ratio	51%
Potential Earnings	13.26
Shares (2015E)	228.50
Potential EPS	$0.06

Source: Company Filings and UBS Estimates

Federal PTC extensions: Wind Industry Boom

We continue to see a great deal of optimism from various industry stakeholders for the extension of production tax credits (PTC) through an extenders bill, to include the 2.3 cents per kWh PTC for wind. In our opinion, an extension is more likely to be a part of a broader package post-election season, albeit after negotiation in the Senate for the recently introduced HR 5559, or the 'Bridge to a Clean Energy Future Act of 2014. It is unlikely that a broad package would pass with just the PTC component dropped. The legislation would extend the PTC, and the option to choose an ITC in lieu of the PTC, through 2016 (with a seemingly 2-year extension to finish projects, implicitly pushing the deadline through 2018); the extension would be effectively a 2-year extension vs. current PTC scheme, which expired at year-end 2014. However, there is some possibility that the extenders get delayed if the GOP wins the Senate, as Republican Senators may push instead for incorporating clauses from the Jobs for America Act through the extender package – which would make the R&D tax credit permanent without any spending offsets or revenue increases.

While a lower rate for the PTC had been previously discussed as part of a long-term feathering out of the tax subsidy, we don't hear much of that rhetoric returning. Rather, the current ask appears to maintain the full 2.3c/kWh without debate.

Broadly, there is support for the extenders on both sides of the aisle, with Senators Harry Reid (Nevada) and Michael Bennett (Colorado) strong supporters on the Democrats side, and support from Senators Mark Kirk (Illinois) and Chuck Grassley (Iowa) from the Republicans. For a longer-term solution, there is also bipartisan support for a permanent solution via tax reforms. The IRS has also written to the Senate urging lawmakers to resolve the uncertainty around extenders by the end of November, given the impact they would have on deductions declared for 2015 filings.

What does this mean? We see a PTC extension as a substantial benefit for the wind industry, including both NextEra (NEE), as well as the entire YieldCo sector, emphasizing disproportionate benfits for NextEra Partners (NEP) as well as Pattern Energy (PEGI), the most wind-biased YieldCo. Coupled with continued improvements in cost, we see continued ability to accelerate wind development off the 2013 drop-off. Particularly when coupled with looming carbon targets associated with EPA's implementation of 111(d), we see a ~2018 deadline for projects (most projects would qualify for the extensions) could see a meaningful acceleration. We suspect wind to increasingly play a meaningful role in merchant markets as PTCs are extended at the current rate.

And what about the solar industry?

The question remains if projects can elect for ITCs in lieu of PTCs, this would appear an implicit extension to the solar industry as well out to 2018 (among the potentials recently discussed by SEIA).

Arizona

Solar interests took a hit in ACC Republican primary in August

Solar interests are not supporting Democratic opposition in this November's ACC elections

Without any serious Democratic constituency for the general election, the Republican primaries effectively decided the final outcome of elections for commissioners to the Arizona Corporation Commission back in August. The winners were Tom Forese and Doug Little, beating out the Solar industry's preferred candidates Lucy Mason and Vernon Parker after a very contentious campaign. We see the primary outcome as among the more constructive data points for shares of late, enabling a clearer run way through 2017. Politically, things have been relatively quiet in the state since the primary, with the Arizona state legislature set to meet again in January.

Comments filed in ACC rate design procedural docket

Pre-filing might not include forecasted load data after all

The rate design pre-filing next year would not include future revenue requirements or forecasted load data. Specifically, the company proposes using Jan-Mar 2015 historical data with the remainder of 2015 forecasted and updated for actual as time passes.

APS, RUCO, and other intervenors all filed comments this week in the ACC's generic docket (AU-00000C-14-0329) to develop procedures to study and consider rate design options for electric and gas utilities. At this early stage, the docket will merely consider whether rate design should be considered as part of the general rate case process or if it should be considered separately ahead of the case (separating would avoid risk of a protracted case). The focus on rate design is deliberately broader than net metering, opening the possibility of remedies such as higher fixed demand & solar charges (~$4.90/mo for avg. system).

In their comments this week, APS argued that a full ratecase pre-filing in Sept/Oct

2015 as contemplated by Staff would essentially be overkill with the potential to bog down the process and possibly derail it. Instead, the utility proposes to file 3-4 months earlier on or before June 1, 2015 with only the bill-determinant information needed for revenue-neutral rate design. This includes kWh, kW, number of customers, and annual revenues based more on current rates rather than future revenue requirements. Specifically, the company proposes using Jan-Mar 2015 historical data with the remainder of 2015 forecasted and updated for actual as time passes. The utility also argues that since these rate design issues are revenue neutral, Arizona statute permits the ACC to consider them outside of a general rate case.

For its part, the Residential Utility Consumer Office (RUCO) argues that there is no support for a bifurcated process to decide rate design outside of the ratecase. i.e. - more workshops.

For its part, the Residential Utility Consumer Office (RUCO) argues that there is no support for a bifurcated process to decide rate design outside of the ratecase. They propose a state-wide discussion (presumably through workshops) on key issues with the goal of having parties align on them. The issues to be discussed include: buy-through rates (AG-1), general rate design (fixed vs variable cost recovery), net metering and distributed gen rates and policies, and Lost Fixed Cost Recovery Mechanisms (LFCR). The ACC would then conduct a formal hearing process for unresolved issue, keeping the entire process more broad that the specific rate design of APS.

The Alliance for Solar Choice argues that a bifurcated process is both unconstitutional and undesirable, as it is necessary to first examine a utility's most current expenses and revenues before determining impacts of proposed rate design. Furthermore, "foundational" rate principles such as gradualism, rate stability, effectiveness, and fairness need to be addressed within the full GRC

process. They also argue that a bifurcated process would be unjustifiably expensive for intervenors to follow, giving an inherent advantage to the utility.

Higher fixed charges and a new rate design are all possible

A central tenet to the next rate case will be the meshing of rate design with rate compensation to offset lost sales from energy efficiency and distributed generation sales. It's unclear whether APS' existing LFCR mechanism will remain in place (partial decoupling), which could yet be replaced/traded for a much more robust compensation structure including meaningfully higher demand charges/fixed charges on customers who opt to shop. Regardless, we see the rate design principles to be crafted in the next year as central to establishing a baseline on which the fate of its riders will be established. Ultimately, we think the commission will be open to settlement in the case, particularly with rate design addressed ahead of time, enabling a consistent return profile.

… But new blood at the ACC limits real progress for now

While we expect additional stakeholder comments and ACC hearings in the coming weeks/moinths, we remain cautious on any tangible progress ahead of the two new ACC commissioners next year. The real question is how much of the net metering discussion can be hashed prior to the next rate case in mid-'16.

For further details on Arizona, please see our 8/1 note "Taking the Solar Concerns Head On" and our 8/27 note "Primary Night Takes: Finding Shade in Arizona".

Another significant victory for PNW after recently winning a GRC filing delay

We expect the win to keep the ACC generally supportive of APS and investor concerns in the coming rate design proceedings as well as the next general ratecase filing in 2016. After recently winning a delay from the ACC in its requirement to file a ratecase back to 2016, this stabilization of the ACC is a significant victory for the company and should ultimately lead to actions to correct the sales erosion and revenue loss from solar rooftop conversions and energy efficiency. Opponents Mason/Parker had run opposing a proposed property tax on leased rooftop solar installations, which still appears to be dead for now in the state legislature. While its possible for the ACC to consider raising the existing $4.90/mo net metering fee on solar rooftops – perhaps to the $20 that had been supported by RUCO – we believe that no changes will be made while broader rate design issues are being considered. This is not likely to take place until 2017 earliest (after the conclusion of the ratecase), and could be completely moot depending on the outcome of rate design reforms and the rate case. More generally speaking, the race in AZ is also indicative of other recent races in which solar and utility advocates increasingly square off in the political arena over net metering subsidies.

We expect the win to keep the ACC generally supportive of APS and investor concerns in the coming rate design proceedings as well as the next general ratecase filing in 2016.

Arizona expected to get serious about net metering reform with new regulators

We expect a (favorable) decision from the ACC on APS' purchase of Four Corners in the next few weeks. We also look for constructive developments on APS' proposed Ocotillo peaker in downtown Tempe (estimated at $600-700 Mn), with '16 construction and 2018 in-service; the plant recently passed the citing committee. Lastly, we see APS' latest solar RFP for an addt'l 20 MW of solar (either

utility-scale or under its novel utility-owned DG program), at a cost of ~$60-70 Mn as also on deck, seeing both ACC commissioner Brenda Burns and Gary Pierce as eager to finalize pending dockets prior to their term expiration at yr-end.

We don't expect any solar policy tariff changes until new rates in 2017

The focus on rate design in AZ is deliberately broader than net metering, opening the possibility of remedies such as fixed demand charges.

It appears to us that the $4.90/month fixed charge currently applied to new customers opting for solar rooftop installations is unlikely to change prior to 2017 under new rates in a general rate case. Rather, once the procedures are agreed upon, we expect the ACC to open a generic proceeding to review what a fair rate design and compensatory regime for solar should be, with the outcome then applied concurrently with new rates in 2017. While we flag the commission had seemingly been in favor of a higher fixed charge initially (around ~$20/mo. on the advice of RUCO, which had advocated this level as its initial 'cost shift' burden—and hence the short turn around on a subsequent rate case), we see the utility as willing to live under the current construct given the added certainty with its existing construct. As a reminder, APS does not benefit from the $5/mo. Payment, as this simply nets against payments made to the utility under the LFCR (which is designed to partially make up for the effects of EE and DG).

Ratebase solar rooftop pilot moving through regulatory considerations

Should the ratebase solar pilot be utility-scale solar or DG rooftop?

APS' proposed 20 MW, ~$65Mn pilot to install ratebased rooftop solar (see below for more details) was kept under consideration after motions to kill the program were dismissed at a Sept 6th procedural hearing. An ACC staff recommendation is expected by the end of October, with commissioners taking up the issue in Nov/Dec (the next ACC meeting is Nov 5). Among the issues being considered are whether the state needs these 20 MW of solar at all, and if needed, should it be utility-scale solar or DG rooftop (utility economics are agnostic on that last point).

Ratebase rooftop solar: not really a game changer

While we see the proposal as an important step, enabling the company to go on the offensive against the effects of DG, it remains to be seen how competitive the company's offering will be versus peers. Criteria include that the (1) customer cannot qualify for a traditional leasing programs (so it will not compete head to head), and (2) roofs are biased towards south/west, with a targeted focus on householders within more specific reliability regions. The program is designed to facilitate solar on lower income customer's roofs, with a fixed monthly discount on consumer bills for allowing APS to install panels on customers' roofs. Importantly, the 20MW, ~$65Mn pilot helps drive more local support from solar developers, as the company seeks to outsource the work to these builders. The company is looking for approval in September, for implementation in December. For further details please consults our 2Q14 earnings note.

APS has proposed both a utility-scale and distributed solution – agnostic on either

Ultimately, we see APS as agnostic to either its utility-scale 20MW solution at the Redhawk CCGT in the desert, or its more novel distributed solution. While it's a bit odd to us of comparable cost (~$3,250/kW), we see the bigger issue as being whether the ACC determines there is need for the capacity to fulfil its obligations. The doubt relates to the current penetration of DG in the state, which is ahead of the targets, as well as projected load growth statistics for the state. Net-net, we're biased to think it still gets approved, as incremental projects are layered in.

Pennsylvania: EPA regs bear watching

Details on new RACT NO_x proposal due out on Nov 7th, but real question is what the new administration will do?

The gubernatorial elections in PA, with the incumbent Tom Corbett (R) and Jim Cawley (R) running for re-election against Tom Wolf (D) and Tom Lineweaver who is running as an independent. Tom Wolf (D) has been leading the incumbent Tom Corbett (R) by significant margins in most polls. The elections could lead to both the Pennsylvania House of Representatives and Pennsylvania State Senate to be held by a single party, potentially turning PA into a a Democratic state government trifecta or keep it a Republican trifecta. Pre-election opinion polls appear to indicate a change towards a democratic administration is more likely.

A unique risk in the state relates to its EPA regulations, which are likely to see finalization in 2015 of a new RACT (Reasonably Available Control Technologies) rules for NOx emissions.

Below we show a list of coal-fired power plants in the state (which are owned by companies we cover), and their NOx and SO2 emissions. We highlight NRG's Seward, and PPL's Brunner Island units as at higher risk from potential stringent emission standards – both these plants are amongst the largest coal plants in the state which still haven't installed Selective Catalytic Reduction (SCR) technology to reduce NOx emissions.

We emphasize while emissions at Bruner Island appear consistent with peers (and Seward even lower), the emissions data appears to suggest that existing plants *don't run their existing environmental equipment*. We suspect requiring their operation will be a baseline to any future regulations, with plants likely achieving at least <0.08lb/MMBtu with full SCRs operating.

While Bruner Island is the most clearly targeted (owned by PPL/Talen), the risk to Seward is if the state wants to impose the most stringent possible targets (which even its SNCR coupled with fluidized coal bed, CFB, technology would not be sufficient to achieve); its emissions are ~0.10/lb MMBtu.

The timeline of any implementation for RACT is likely due late in the decade, earliest, with rules only published next year.

Lastly, we expect the emissions profile of NOx in the state to change modestly with the forthcoming implementation of CSAPR once again in 2015, reflecting a slight tightening (and a further tightening in 2017 under Phase II).

Figure 3: Historic NO_x and SO_2 emissions at PA coal-fired plants – Establishing a baseline

Power Plant Unit	Ultimate Parent	Capacity (MW)	Capacity Factor 2013	NOx Emissions (lbs/mmbtu) 2013	2012	2011	SO2 Emissions (lbs/mmbtu) 2013	2012	2011	Technology
Beaver Valley ST GEN2	AES Corporation	35.0	NA	0.34	0.42	0.41	0.49	0.48	0.50	
Beaver Valley ST GEN3	AES Corporation	114.0	NA	0.49	0.50	0.45	0.54	0.50	0.51	
Eddystone 3-4 3	Exelon Corporation	391.0	0.67	0.13	0.16	0.12	0.09	0.22	0.08	
Eddystone 3-4 4	Exelon Corporation	391.0	0.40	0.15	0.16	0.13	0.13	0.20	0.08	
Fairless Hills Steam A	Exelon Corporation	30.0	14.66	0.05	0.05	0.04	0.04	0.04	0.04	
Fairless Hills Steam B	Exelon Corporation	30.0	76.67	0.05	0.06	0.05	0.04	0.04	0.04	
Bruce Mansfield 1	FirstEnergy Corp.	913.7	80.91	0.17	0.10	0.15	0.11	0.16	0.20	
Bruce Mansfield 2	FirstEnergy Corp.	913.7	71.80	0.16	0.12	0.11	0.12	0.18	0.23	
Bruce Mansfield 3	FirstEnergy Corp.	913.7	85.77	0.20	0.11	0.15	0.35	0.30	0.31	
Cheswick 1	NRG Energy, Inc.	637.0	57.08	0.36	0.36	0.25	0.11	0.15	0.71	Scrubber
New Castle 3	NRG Energy, Inc.	98.0	11.85	0.38	0.36	0.36	2.39	2.31	2.25	
New Castle 4	NRG Energy, Inc.	114.0	16.07	0.35	0.33	0.35	2.37	2.23	2.29	
New Castle 5	NRG Energy, Inc.	136.0	14.07	0.44	0.46	0.47	2.44	2.34	2.33	SCR/Scrubber
Seward Waste Coal FB1	NRG Energy, Inc.	585.0	39.50	0.10	0.09	0.10	0.43	0.42	0.41	
Shawville 1	NRG Energy, Inc.	125.0	25.88	0.43	0.43	0.44	2.92	2.87	2.94	Scrubber
Shawville 2	NRG Energy, Inc.	125.0	30.43	0.43	0.45	0.45	2.98	2.91	2.95	
Shawville 3	NRG Energy, Inc.	188.0	39.38	0.38	0.38	0.39	2.96	2.87	2.95	Scrubber
Shawville 4	NRG Energy, Inc.	188.0	25.88	0.41	0.39	0.39	2.98	2.89	2.89	Scrubber
Brunner Island 1	PPL Corporation	363.3	55.09	0.38	0.40	0.37	0.35	0.42	0.39	Scrubber
Brunner Island 2	PPL Corporation	405.0	48.51	0.36	0.39	0.36	0.40	0.42	0.39	Scrubber
Brunner Island 3	PPL Corporation	790.4	54.78	0.37	0.37	0.38	0.37	0.41	0.39	Scrubber
Martins Creek 3 and 4 3	PPL Corporation	850.5	4.04	0.15	0.18	0.20	0.04	0.01	0.07	
Martins Creek 3 and 4 4	PPL Corporation	850.5	5.41	0.19	0.23	0.26	0.04	0.02	0.06	
Montour 1	PPL Corporation	805.5	53.35	0.39	0.40	0.33	0.35	0.38	0.42	Scrubber
Montour 11	PPL Corporation	17.2	0.00	na	na	na	na	na	na	
Montour 2	PPL Corporation	819.0	52.89	0.39	0.39	0.28	0.39	0.41	0.43	Scrubber
Keystone 1	PPL Corp (about to acquire)	936.0	80.39	0.28	0.37	0.38	0.50	0.68	0.86	Scrubber
Keystone 2	PPL Corp (about to acquire)	936.0	86.89	0.27	0.36	0.37	0.38	0.54	0.82	Scrubber

Source: SNL

Ohio

Don't see policies changing with Kasich safe in office

We believe that with Governor Kasich enjoying a commanding 22% lead, the state's priorities are unlikely to change soon, with Kasich remaining focussed on economic improvement and jobs as one of his highest priorities. Furthermore, it is our belief that Ohio's significant shale-driven economic jumpstart in recent years likely places electric competition in a definitive second place (or further) versus the more important goal of ensuring that the new oil and gas wealth effect spreads to other industries. In this regard, we believe that the scales are tipped generally in favor of PPAs for FE's and AEP's merchant coal fleets, despite Public Utilities Commission of Ohio (PUCO) staff opposition.

However, there are limits – we don't see PPA's for plants other than Conesville and Sammis (and certainly not troubled Davis Besse). We also don't see PPA pricing as above-market as our analysis below would suggest either.

However, there are limits – we don't see PPA's for plants other than Conesville and Sammis (and certainly not troubled Davis Besse). We also don't see PPA pricing as above-market as our analysis below would suggest either. We don't see resolution on either AEP's or FE 's Electric Security Plan (ESP) until after the elections, with hearings for FE in late January followed by a request for a final decision on April 8 (soon enough to give FE a year to begin hedging the result).

Who win's with a contract? While FirstEnergy nominally benefits, we suspect the bigger beneficiary from a contract would be AEP given its relatively less-levered business (allowing equity value to accrue back to shareholders).

Ohio Docket Growing Increasing Crowded

FE's application for generator assistance has led to AEP following with a similar filing but the same punchline – asking for an above-market contract.

FE filed its Electric Security Plan in Ohio in early August which if approved by PUCO would award the company's merchant business with a PPA-rider for ~3.2GW of generation. We have estimated that the PPA would begin at ~$65/MWh and rise by $2/MWh per year – essentially backing-into a ~$21/MWh uplift on current power and capacity prices. While we have written about the potential for a $50+/MW-Day improvement in the upcoming PJM capacity market, a $50/MW-Day improvement would still imply that the PPA would be $19/MWh above market.

FE has asked for a decision in April, notably before capacity auction bidding decisions have to be made.

The statutory deadline for FE's decision is May 2015; however, management has requested a decision a month earlier on April 8 so that it can adjust its strategy for the capacity auction, etc. appropriately. The docket is seeing an increasing number of interveners including EPSA (Power trade association), P3 (PJM-specific power trade association), and DYN among other generators. We see this as among the few issues in recent memory where the industry could be poised to see in-fighting on a question of higher compensation for existing generators. We flag efforts by EXC in Illinois (also an intervenor in FE's case) to save its nuclear fleet remain particularly committed to a 'market' solution (renewable, carbon, etc.) rather than bilateral approach taken in OH.

FirstEnergy's testimony and hearings on the proposal are set for December 19th and January 20th, respectively. Settlement negotiations typically take place in this window, and we understand this is indeed the intention on the current filing as well. We caution that Staff is likely to be persistent in rejecting against the contract in its initial testimony

AEP follows FE's lead on compensation for its Ohio coal fleet

Since the FE filing, AEP has followed the same path with a very similar request for an initial $2/MWh PPA rider for 2.7GW of its Ohio merchant coal (4 of 5 stations) for the life of the assets. AEP stated that a motivation for the request is that it "eliminates investor reluctance to the State of Ohio". While Staff notably rejected the notion of even including a rider for AEP's stake in OVEC under its testimony in the existing ESP docket, we wouldn't be surprised to see the subject revisited by the Commission (even outside of the current case). AEP has asked for the contract to take effect in June 2015.

Figure 4: AEP's merchant coal portfolio

PJM Fleet Stats	Capacity (MWs)	Cap Factor	Output (TWhs)		Seeking Contract?
Coal Units					
Cardinal	595	55%	3		Yes
Stuart	603	55%	3		Yes
Gavin	2,640	55%	13		
Zimmer	330	55%	2		Yes
Mitchell (Retiring in 2015)	780	55%	4		
Conesville	1,139	55%	5		Yes
Total AEP Merchant Coal in Ohio	6,087			Total MWs:	2,667

Source: Company reports and UBS estimates

No requirement to clear RPM, avoiding jurisdiction issues

Will NOT follow the NJ and MD example – most likely

The request notably does not require the plants to clear the RPM capacity auction in order to be paid. This should help avoid the problems encountered in Maryland last year when the state sought to encourage new generation construction with state PPAs that were conditional on clearing capacity markets (with the intention of providing customers a net benefit). Recall that the Maryland PPAs were rejected by the courts as state interference in PJM's interstate commerce and the FERC's authority to regulate capacity pricing under the Federal Power Act.

For additional details, see our 10/15 note 3Q14 Earnings Playbook: Trading Tips for Turbulent Times

Contract Proposals Appear Materially Above Market

We think AEP may have greater leverage to contracting approvals than FE given its un-levered Genco

Max upside case is ~$0.28

Below we present our estimations of the plans for each of the four plants as well as our underlying assumptions. While AEP states that the average customer would see a $2/MWh uplift initially, we estimate the uplift to the plants is closer to ~$19/MWh based on our latest assumptions of forward curves. A big swing factor remains the capacity factor projected on the units, which appears to be a key variance in our assumptions (as was seemingly the case in our prior FE calculations). We estimate FE's request is closer to ~$21/MWh above market.

- We estimate the benefit to AEP at **$0.12 EPS for just Conesville** assuming economics below, with more meaningful upside if additional plants are approved. Our baseline remains just one plant from FE & AEP each is retained.
- The table below *excludes* the proposed rider for the additional 435 MW of capacity through AEP's interest in the OVEC plant, included in the original ESP.

Figure 5: AEP Projections – Fundamental assumptions suggest significantly above market as well

Regulatory assumptions	
ROE	11.23%
Effective tax rate	37%
Assumed debt (%)	50%
Assumed equity (%)	50%
Cost of debt	4.73%

UBS view vs filed assumptions for 2017	
2017 Power Revenues	605.3
2017 Capacity Revenues	85.9
Total UBS projected PJM revenues	705.1
AEP Projections of PJM Revenue (Using Avg of High/Low Forecast)	920.0
Difference in PJM Revenue Assumptions ($mn)	214.9
Total Estimated Generation	14.7
Above market price, UBSe vs. AEP Calcs on PJM Rev's ($/MWh)	**14.7**
AEP Projections of Agreement Costs	912.0
Difference in UBSe PJM Revenue vs. Agreement Costs	206.9
Above market price, UBSe vs. Agreement Costs ($/MWh)	**14.1**

Cardinal		**2017**
AEP's Owned Capacity (MW)		592
Capacity factor, UBSe		70%
Generation (TWh)		3.6
Fuel Cost ($/MWh)		25.0
O&M ($/kW-yr), UBSe		50.0
O&M ($ Mn)		29.6
Power Prices ($/MWh), AD Hub - Avg Peak/ATC		41
Capacity Prices	59	120.0
Annualized Capacity ($/MW-day)		94.7
EFOR (%)		7%
Capacity Payments ($ Mn)		19.0
EBITDA		**48.6**
Maintenance Capex ($/kW)		5.0
Maintenance Capex ($ Mn)		3.0
FCF		**45.7**

Conesville		**2017**
AEP's Owned Capacity (MW)		1,149
Capacity factor, UBSe		50%
Generation (TWh)		5.0
Fuel Cost ($/MWh)		29.9
O&M ($/kW-yr)		50.0
O&M ($ Mn)		57.5
Power Prices ($/MWh), AD Hub - On Peak		45
Capacity Prices	59	120.0
Annualized Capacity ($/MW-day)		94.7
EFOR (%)		7%
Capacity Payments ($ Mn)		37.0
EBITDA		**54.2**
Maintenance Capex ($/kW)		5.0
Maintenance Capex ($ Mn)		5.7
FCF		**48.5**

Stuart		**2017**
AEP's Owned Capacity (MW)		600
Capacity factor, UBSe		70%
Generation (TWh)		3.7
Fuel Cost ($/MWh)		26.7
O&M ($/kW-yr)		50.0
O&M ($ Mn)		30.0
Power Prices ($/MWh), AD Hub		41
Capacity Prices	59	120.0
Annualized Capacity ($/MW-day)		94.7
EFOR (%)		7%
Capacity Payments ($ Mn)		19.3
EBITDA		**42.9**
Maintenance Capex ($/kW)		5.0
Maintenance Capex ($ Mn)		3.0
FCF		**39.9**

Zimmer		**2017**
AEP's Owned Capacity (MW)		330
Capacity factor, UBSe		80%
Generation (TWh)		2.3
Fuel Cost ($/MWh)		25.8
O&M ($/kW-yr)		50
O&M ($ Mn)		16.5
Power Prices ($/MWh), AD Hub		40
Capacity Prices	59	120.0
Annualized Capacity ($/MW-day)		94.7
EFOR (%)		7%
Capacity Payments ($ Mn)		10.6
EBITDA		**26.27**
Maintenance Capex ($/kW)		5
Maintenance Capex ($ Mn)		1.65
FCF		**24.6**

Source: AEP Filing before the PUCO, Company reports, SNL, and UBS estimates

Understanding the discrepancy in EPS uplift

We emphasize that the discrepancy between our EPS estimate and management's implied EPS estimate from its filing relates to the assumed revenues to the plants. We estimate our revenues using 2017 annualized capacity payments and peak-weighted AD Hub prices. We think the discrepancy is likely due to differences in capacity factors, ancillary revenues, and out-of-market assumptions for the forward curve.

But where's the pushback? We believe price at a minimum.

The question remains *why* Ohio would need to contract for these plants now – and under whose interest. Given the focus on not just jobs, but also long-term rate stability and perceived value, we view the exact pricing of any deal will be critical to any eventual settlement. Notably different from previous interventions, there is not the explicit threat (yet) of plant retirements without payments.

What's next? Looking towards FirstEnergy's process

We flag that FirstEnergy's testimony and hearings on the proposal are set for December 19th and January 20th, respectively. Settlement negotiations typically take place in this window, and we understand this is indeed the intention on the current filing as well. We caution that Staff is likely to be persistent in rejecting against the contract in its initial testimony.

But where will the power industry come out on this: Don't feed the bears?

We flag that EPSA (Power trade association), P3 (PJM-specific power trade association), and DYN appear opposed to the OH contracts despite the requests from AEP & FE. We see this as among the few issues in recent memory where the industry could be poised to see in-fighting on a question of higher compensation

for existing generators. We flag efforts by EXC in Illinois to save its nuclear fleet remain particularly committed to a 'market' solution (renewable, carbon, etc.) rather than bilateral approach taken in OH.

Kansas

Given that Democratic challenger Davis remains quite moderate in this thoroughly red state, we believe the risk to tax rates and economic growth is likely just as moderate.

The race between Republican Governor Sam Brownback and Democratic challenger Paul Davis is running close with Brownback at a 3 point lead 48%-45%. Brownback's pro-business policies in the state, such as the elimination of income taxes for small businesses and the reduction of individual tax rates could be at risk in the event of a Davis victory. However, given that Davis remains quite moderate as far as Democrats go in this thoroughly red state, we believe the risk is likely just as moderate. Furthermore, Davis would likely throw even stronger support toward renewable energy standards given the opposition to renewables thrown at the Governor by Americans for Prosperity, a Koch brothers' anti-tax-subsidy organization.

At the Kansas Corporation Commission (KCC), Commissioner Jay Elmer's partial term expires in March 2015, which could give a victorious Davis the opportunity to replace a Republican commissioner with a Democrat (leaving the KCC with on each - a Republican, a Democrat, and an Independent). However, we don't think a replacement would necessarily happen until closer to yearend 2015 given that GXP's general ratecase would only be 3 months old and WR will be filing their ratecase in April. Pat Apple (R)'s term expires in March 2018 and Chairperson Shari Albrecht (I)'s term expires in March 2016.

Michigan

Support for renewables continues under either candidate

RPS appears to go up in either scenario?

While it appears that Governor Snyder has had a fairly consistent lead in recent polls of ~4%-5%, the race is still considered a toss-up. So far, energy policy has not been a significant campaign issue, with both the governor and Democratic challenger Mark Schauer fairly supportive of energy efficiency programs and raising renewable standards from the current 10% to 15% or perhaps higher in 2015. We see a higher RPS as largely a benfit to the states' two IOUs, CMS and DTE, enabling further potential development/ownership opportunity/

Shopping could be addressed through a new legislative energy package next year

Retail open access (ROA) laws could be revised or eliminated through a more comprehensive energy package next year following this year's failed attempt by state Rep Mike Shirkey to pass the Michigan Electric Customer Freedom Act, which would have eliminated the 10% retail shopping cap and opened electric retail up to full competition. Rather than full competition, legislative action to eliminate industrial and large commercial (I&C) shopping in the state next year could help reduce overall I&C rates significantly as costs are once again spread over the entire customer base. Combined with rate re-design as described below, this has the potential to create meaningful economic uplift in the state. CMS has also stated that the elimination of ROA would also require CMS to acquire or build (in ratebase) about 800 MW of generation to serve returning load. We see any rolling back of this policy as a meaningful ratebase addition opportunity amidst the concerns over resource adequacy in the state as well as reducing the overall regulatory risk in the jurisdiction (given historic concerns around an *increase* in the cap).

New rate design to boost economic and business development

This past Summer, CMS, DTE, large industrial customers, and regulatory Staff agreed on a recommendation for a new rate design methodology that would effectively reduce industrial rates as much as 5% and commercial rates 1% at the expense of residential customers, who might see their rates rise by 2.5%, but still remain competitive vs the rest of the country. The idea is to create a more fair rate design, especially for heavy usage industrial customers, that would encourage economic development and a business-friendly environment. CMS's next ratecase filing on Dec 1 will likely include the new rate design within it.

Concern over Quackenbush likely overblown

Some investors have been concerned that should Schauer win, he could name his own replacement for Commissioner Greg White when his term ends in July 2015 and appoint that person as Chair, replacing John Quackenbush. As a former senior investment analyst responsible for equity research for the transportation, utilities and coal industries at UBS Global Asset Management, Quackenbush is heavily favored by investors for his understanding of financial issues and fairness. Some investors fear that he would resign from the PSC if he lost the Chair before the expiration of his term in July 2017. However, we do not believe that to be the case given his desire to serve and live in Michigan as major reasons for applying for the job in the first place. We also note that should Synder win re-election, he would have the opportunity to replace Greg White himself, resulting in having appointed all three sitting commissioners himself at that time.

Could Michigan turn the screws on WEC-TEG?

While the topic hasn't yet surfaced as an election issue, we note the potential for Michigan to use its authority to approve the WEC-TEG merger in order to force a compromise on WEC's recently FERC-approved proposal to shift 99% of Presque Isle-related SSR payments onto Michigan customers. The WEC proposal creates two Balancing Authorities (BA) which separate out the Upper Peninsula, effectively addressing the cost sharing issue between the two regions for the Presque Isle plant. The Michigan PSC argues that WEPCo's proposal to create two new BAs would result in the System Support Resource (SSR) costs being borne by Michigan customers "as high as 99%" versus 14% Michigan/86% Wisconsin previously. The Michigan PSC opposes the proposal on operational grounds (that the cost shift is "so grossly unjust and unreasonable") as well as procedural (lack of proper notice). Docket EL14-104.

The potential to force a compromise on WEC's recently FERC-approved proposal to shift 99% of Presque Isle-related SSR payments onto Michigan customers.

As further background on this issue, earlier this summer the FERC ruled in favor of WEC customers who had complained about $26M of costs related to out-of-market System Support Resource (SSR) payments made to keep the Michigan-based Presque Isle plant running for reliability. FERC agreed that the reliability benefits accrued to Michigan customers rather than Wisconsin ratepayers, who had been responsible thus far due to a quirk of MISO rules and the location of the plant within American Transmission Company's (ATC) footprint. The ruling will have no direct effect on WEC earnings (just who pays).

The ruling will have no direct effect on WEC earnings (just who pays).

MI's Quackenbush discusses future of renewables, EE, and the fate of potential customer switching reform

We recently met with Michigan PSC Commissioner John Quackenbush where he presented his opinions on Michigan and the direction of public policy. In November 2013, Michigan released four reports on (1) Energy Efficiency, (2) Renewables, (3), Electric Choice, and (4) Other topics. With respect to Energy Efficiency/Optimization (EO) Michigan as a 1% annual savings target for electricity (following a ramp-up period from 2009-2012) and the utilities have exceeded the MWh targets every year. The PSC forecasts a 30.1%-33.8% potential reduction in forecasted electric kWh sales off of 2023 projection over the next ten years (2014-2023). A more achievable target is in the range of 13.5%-15.0% while a constrained potential scenario of reduction is 5.7% as this latter scenario limits utilities to spending 2% of revenues on EO (PA 295). We look for EO to remain a priority due to the magnifier effect where the PSC estimates that every $1 of EO spending in 2012 will result in benefits of $4.07, although we expect diminishing returns.

Michigan continues to meet and exceed its 1% annual EE target.

Figure 6: Electrical Energy Efficiency in MI

Electrical Energy Efficiency	
EO Scenarios	*Forecast kWh Savings*
Economic Potential	30.1%-33.8%
Achievable Potential	13.5%-15.0%
Constrained Potential	5.70%

Source: Michigan PSC

For Renewable Portfolio Standards (RPS), the most popular public comment area by a wide margin has been the design of RPS. The vast majority of renewables in Michigan are wind assets following development in 2012, although biomass and solar are increasing in the state. Currently Michigan has a 10% RPS, which the state's utility companies are on track to achieve, and we look for it to essentially increase by ~1% per year (scenarios included 15% RPS in 2020, 20% RPS in 2025, etc. up to 30% by 2035), scenarios that the PSC believes are achievable even if Production Tax Credits (PTC) are not renewed. While coal still represents over 50% of Michigan's generation, it is a lower percent than for regional peers such as Ohio. Michigan wind remains challenging but the economics have improved over the past few years with recent projects pricing at $50-60/MWh due to taller towers and larger blades resulting in higher capacity factors.

RPS standards are set to effectively increase in MI by ~1% per year, a target that the PSC believes is achievable even without PTC extensions.

Electric Choice remains a hot topic in Michigan despite the fact that consumers in the state have average annual bills that are 15%+ lower than the national average due to lower usage. Currently there is a 10% cap per utility based on prior year's sales and most utilities in the state are at the cap with large number of customers in the queue to switch. The notable exception relates to WEC's WEPCO which saw its large mining customers switch to TEG, resulting in 85%+ participating and effectively resulting in WEC's decision to close the Presque Isle Plant in the UP.

The current situation with WEC's Presque Isle plant highlights the shortcomings of Electric Choice in Michigan as it is currently constructed.

On the topic of the recently discussed potential litigation to remove the current direct access cap, Quackenbush believes that drastic policy change is unlikely this year due to the elections. We continue to expect some type of reform to the switching program, potentially a longer 'lock-up' period between switching, to remove some of the free option characteristic.

We see no chance of an upwards revision in the cap; rather, the question is full reversal?

Figure 7: Michigan Retail Switching Statistics

Utility Parent	Consumers CMS	DTE Electric DTE	I&M AEP	UPPCO TEG	WEPCO WEC	WPSC TEG
2012 Sales (TWh)	37.3	46.8	2.8	0.8	2.5	0.3
Participation Level	4.0	5.2	0.0	0.1	2.2	0.0
Particiation %	10.76%	11.03%	0.00%	10.00%	85.23%	7.53%
Current In-Service Customers	1069	5521	0	38	51	13
Customers in Queue	6082	5261	0	13	2	0
Load in Queue	5.3	5.2	0.0	0.0	0.0	0.0
Particiation without Cap	25.10%	22.09%	N/A	10.43%	85.31%	N/A

Source: Michigan PSC

Lastly, when asked about the variance between authorized ROEs between the large utilities operating in Michigan, Quackenbush held the opinion that the distribution was tight and attributed much of the spread to timing differences for when rate cases were filed rather than larger identifiable variances in the risk profiles. On the electric side the most recent rate cases range from 2011 to 2013 with ROEs between 10.1% and 10.5%. Currently only CMS and TEG have rate cases pending in Michigan and are pursuing 10.5% and 10.75% ROEs, respectively.

Figure 8: Electric Rate Cases

Ticker	Completion	ROE
CMS	2013	10.3%
DTE	2011	10.5%
AEP	2012	10.2%
TEG	2011	10.2%
WEC	2012	10.1%

Source: SNL/RRA

The sun shines in Michigan too – sometimes

The Michigan Public Service Commission (PSC) Staff's Solar Working Group issued a draft report in June detailing ways in which DTE Energy and CMS Energy could promote residential adoption of solar. Despite estimating only a 14% capacity

factor, it is clear that Michigan and its utilities want to stay at the forefront of the solar net metering debate. The report presents two broad options: net metering or solar Value of Service (VOS) credits. The PSC Staff stressed that its objective was a "properly designed" system where both the utility and customers would be indifferent with respect to cost while ensuring that low-income customers were not disproportionately impacted by the policies.

Under the net metering scenario, customers would opt into the current net metering program and sell-back to the utility at the full energy plus distribution rate as well as receive the REC credit ($0.125/kWh credit + $0.025/kWh REC credit). The VOS scenario differs in that a $0.10/kWh credit would be used in addition to a $0.05/kWh REC credit. In both scenarios there is a $6/month customer charge. A hybrid scenario involves generation sent 'back-to-the-grid' being credited to the customer at VOS and all solar generation receiving the REC credit. The net metering option could be implanted by the respective utility filing a renewable energy plan under the current existing solar policy and changing the renewable surcharge. DTE has been vocal in the past that it opposes subsidies for solar and estimated in the draft report that the cross-subsidization of net metering would be $0.09/kWh. Both DTE and CMS have relied thus far primarily on wind to meet their renewable portfolio standard (RPS) needs. The second and third options rely on a VOS credit and would likely need a PSC proceeding to become possible.

Aside from the typical residential rooftop opportunities, the PSC staff expressed interest in community solar and has stated that "50% company-owned and 50% developer/customer owned community solar limits would allow for a price competitive atmosphere where program innovation and best practices would thrive." *Case No. U-17302*

New York

While Governor Cuomo's seat looks safe, we suspect he is saving more meaningful, more controversial updates on state energy policy until after the election. Stability in the Governor's house also likely means continued support for the PSC's Reforming Energy Vision (REV) docket that could continue to benefit ED as it begins to assume its proposed distribution resource dispatch role.

Governor Cuomo's seat looks safe, and we don't expect much more momentum in the near term for either ED's AC Transmission proposals or the Indian Point Contingency proposals, especially with NY capacity prices likely peaking as a result of recently announced capacity additions.

What about Indian Point? Rhetoric more than reality following meaningful experienced infalation. It's not clear the state will return to the subject of the Indian Point contingency planning, seeing the Governor's office as particularly sensitive to raising customers bill *further* in the Lower Hudson Valley (LHV) zone following the capacity price uplift. Presumably any new

Addressing the LHV capacity uplift through transmission, not regulatory. Following months of continued focus on higher capacity prices – with shrill political cries threatening to defund FERC on the back of this customer increase – we see some will to effectively 'de-constrain' the LHV zone through new transmission imports (and implicitly already through new capacity via the Danskammer contract with CHE&G). Net-net, keeping localized inflation down will likely be a gating item for the governor

And what about Ginna? Still awaiting a reliability contract. We think New York wlil likely award a broadly socialized deal to keep the nuclear plant alive, also after the election, rather than impacting just RG&E customers. We see general downside to medium term forwards in NYISO Zone A on the back of any developments here.

Increased natural gas demand – will new Supply be approved?

We expect to see up to 750 dTh/day of incremental gas demand to the NYC area through the remainder of the decade as a result of both electric plant and oil heat conversions to natural gas. The question is whether there is an acceleration of planned pipeline development under the new administration, with the key question being its blessing of the controversial WMB's Constitution pipeline (delivering from Marcellus in PA).

AC Transmission Docket Still Exists…

Looking for developments late this year/early 2015, post-election

ED management has confirmed that there has been minimal progress on Con Ed's AC Transmission proposal or any other Indian Point contingency projects outside of the "no regrets" plans; we understand work on this project is anticipated to pick up once again following the November elections. In February the PSC instructed the three bidders to re-submit their proposals using existing right-of-ways (largely owned by ED) but overall it looks like progress has stalled here, again looking like no real projects will pick up steam ahead of the November election. Recent comments on the docket have focused on cost recovery, allocation, risk sharing, etc. but do not bring us closer to having direction.

Moreover, with both the PSC and NYISO unsuccessful in stemming implementation of the Lower Hudson Valley (LHV) capacity zone, we believe efforts to alleviate the congestion in the zone could yet add to efforts to expedite new transmission projects in the state.

Dockets: 12-T-0502 (AC Transmission) and 12-E-0503 (Indian Point Contingency)

NY PSC proposal to support expansion of distributed energy resources

PSC straw proposal with recommendations on the REV initiative, which addresses how regulation can be modified to enable utilities to manage integration of distributed energy resources

The NY PSC Staff filed a straw proposal on August 22nd with subsequent comments as part of the Reforming Energy Vision (REV) docket. The REV initiative underlines our own expectation that distributed PV solar will continue to expand in the northeastern markets, and calls for regulatory support for peripheral investments.

Networks capex in the state are being catalyzed by specific characteristics of the NY market such as increasing 'peakiness' of the demand curve, and a generally aging infrastructure (~14GW of non-hydro generation assets are more than 40 years old) – and the case for regulatory support needs to be seen against a backdrop of low load growth (projected to be 0.16% per year through 2024).

Proposals recommend exiting utilities can serve as Distributed System Platform

Should the DSP be an incumbent utility or an independent entity? Proposals say existing utilities should be the DSP

Under the REV, the PSC is investigating how existing regulation can be modified so as to allow power utility companies (both regulated and unregulated participants) to be compensated for managing their infrastructure to complement distributed energy resources (DER). To support the expansion of DER, the proposals support the formulation of a Distributed System Platform (DSP) – 'an intelligent network platform that will provide safe, reliable and efficient electric services by integrating diverse resources to meet customers' and society's evolving needs'. Some key policy recommendations made by the PSC staff in the proposals – which we find interesting - include:

- Existing utilities in the market should serve as the DSP, and their long-term status as DSP providers should be subject to performance reviews
- DER providers that satisfy Commission requirements should have access to individual customer usage data (who will have an opt-out option)
- Utilities can be allowed to own DERs too subject to conditions, and an approved plan
- Market power protections should be put in place if utility affiliates participate in DSP markets within the service territory operated by their parent company
- Steps taken in the near term to develop demand response tariffs for all service territories, including tariffs for storage and energy efficiency
- the Commission should exercise oversight of DER providers to protect consumers and reliability of service
- A benefit-cost framework should be defined appropriate to three different purposes: (1) utility DSP implementation plans; (2) periodic utility resource plans; and (3) pricing and procurement of DER; and
- As a transition toward market-based approaches to increase levels of efficiency and renewables, utilities should integrate energy efficiency into their regular operations and should take responsibility for procurement of Main Tier renewables.

Although we expect any actual regulatory outcome to take shape over the course of *years*, the current proposals focus on more near-term measures required to move towards the final goal. In the immediate term reply comments will be

accepted until October 24th with a second technical conference on policy questions November 6th.

Unlike the REV Track 1, REV Track 2 (generic policy decisions on design) has yet to get started as the initial PSC Staff options paper was not filed by the October 3rd target; the next key date had been the Staff straw proposal by January 30th. Without an updated schedule this puts additional risk on the entire timeline which targeted comments through March 2015 and a PSC policy determination in 2Q15.

Not yet at the starting gate for Track 2.

Can Utility 2.0 get off the ground? Starting with 1.5

While we increasingly view the REV 'Utility 2.0' compact proposed by the NY PSC as a net benefit to utilities (despite their more cautious attitudes), we believe significant implementation hurdles remain. Perhaps most notably, we sense a palpable sense of skepticism from a wide array of constituents over a seeming 'over-reach' of the PSC in terms of setting a wide ranging agenda.

The question remains what could the Utility 2.0 initiative include? We believe a lot is on the table. While likely the more controversial and slow-moving aspect of the reforms, we see the potential to accelerate capital spend at CECoNY on the back of reforms designed to build out 'behind-the-meter'. As an interesting gating item, we see a potential for a renewed discussion on smart meter rollout, seeing the city opted to forgo installation as too costly in 2006.

More broadly, we look towards whether the REV structure will lead to a long-dated rate deal in next year's CECONY rate case as part of efforts to emulate the UK's rate experience.

Is ConEd the guinea pig on the new rate model?

We understand the PSC continues to aim to implement new rate filings under a more RIIO (UK) model beginning with rate cases next year; ConEd's New York case is likely to be the first filed under this new structure (ambitiously); however, the recent delays in the process could impact timing. If successful, we believe implementation would be warmly received by the investment community with the goal of a protracted stay-out, with explicit (and well delineated) performance objectives. The PSC has a stated goal of implementing this new rate structure across all of the states' utilities by ~2017. We see the RIIO transition as among the easiest reforms to implement, reducing the risk profile of the utilities if done right (and again, given NY's more strained history with its utilities, we emphasize if done right). This could drive a re-rating higher in what has historically proven a challenging regulatory dynamic.

A long-term rate deal (up 5-to-8 years?) would likely be positively perceived by investors

Con Ed proposes 'Utility 1.5', a step towards 2.0

In July Con Ed filed a proposal with the NY PSC for a Brooklyn/Queens Demand Management Program (BQDM) with the hope of investing $200Mn into customer demand management programs to defer the need for an estimated ~$1Bn substation. ED is prepared to spend $25Mn from the currently approved demand side management (DSM) program (largely under competitively solicitations) but is requesting approval to spend $200Mn on demand management. Based on Con Ed's current projections the Brownsville No. 1 & 2 Brooklyn substations are overloaded necessitating the aforementioned new substation by 2017 and related sub-transmission feeders. Currently management believes that it will be able to meet the higher load in 2014-2015 with "operational measures" but foresees a shortfall after that point.

ED hopes to spend $200Mn short-term to defer need for $1Bn substation in intermediate-term

If successful the demand management programs could shave 52MW of demand and utility investments (capacitors, load transfers, and other investments) would account for 17MW (undisclosed capital cost), by 2018 thereby offsetting the projected 69MW of excess load forecasted.

Projected Load Increase: 69MW
Offset by:
41MW of Customer DSM
11MW of Utility DSM
17MW Utility Investment

- **Customer Side:** 41MW for $150Mn ($3.7Mn per MW); 5 year recovery via customer surcharge
- **Utility Side:** 11MW for $50Mn ($4.5Mn per MW); 10 year recovery via customer surcharge

Additionally management is requesting a 100bp incentive on investments based upon achievement of benchmarks to spur spending in this area. Net cost savings would be shared 50%/50% between customers and Con Ed, as defined as cost of the original new substation less collections from the BQDM program.

Incentive mechanisms with cost benefit sharing could be the model of 'Utility 2.0'.

The proposal focuses on Brooklyn and Queens due to the population growth in those regions and the unique nature of its load that differs from other regions of Con Ed's service territory (~12 hour peak from 12PM to 12AM). ED's proposal is a step towards the PSC's Reforming the Energy Vision (REV) model discussed above. The docket was notably silent until the beginning of October where the IPPs of New York and the City of New York have provided comments. While the generators oppose ED owning any form of generation, even DG, the City is concerned about the rate impact primarily (a key topic of late especially with the creation of the LHV Zone). The docket lacks a concrete timeline (following a similar theme as above) with the initial comment period now closed.

BQDM docket remained eerily quiet until early October when the natural intervenors commented.

Dockets: 14-M-0101 (REV), 14-E-0302 (BQDM), and 13-E-0030 (ED)

Massachusetts, Connecticut, RI, New Hampshire

Connecticut and Massachusetts races are tight but New Hampshire isn't

In Connecticut, Governor Malloy (D) is in a dead heat with Republican challenger Tom Foley (R) at 45%. Foley has had no explicit energy policy while Governor Malloy has had a fairly forward-looking energy policy, including support for legislation to expand natural gas infrastructure as well as the counting of large hydroelectric power as a renewable resource.

In Massachusetts, the incumbent Deval Patrick is not running, and the two candidates are in a dead heat with both Charlie Baker (R) and Martha Coakley (D) tied at 43% vs 42%, respectively. No matter who wins in Mass, we expect less emphasis on expensive renewable procurement than Governor Patrick, which would eventually result in less overall retail rate pressure for NU and National Grid. We also note that the new Governor will have the opportunity to appoint two new commissioners of three at the Department of Public Utilities (DPU), which could have an impact on NSTAR Electric's next ratecase filing no later than 1H17. The last NSTAR litigated ratecase was 20 years ago, with cost cuts and a series of trackers for pension, reliability investments, and lost base revenues from promoting energy conservation programs keeping ROEs at or above authorized levels in the interim. Furthermore, there has been essentially no intervenor pressure to reduce rates since the utility entered a four year rate freeze through Jan 2016. In NSTAR Electric's 2013 annual regulatory filings, ROE for the combined transmission and distribution assets was 11.47%, including transmission ROE incentives. Excluding incentives, the ROE was 11.11%. The utility's last rate settlement for 2006-2012 authorized a 10.5% ROE +/- 200 bps and we estimate that transmission assets are approximately 25%-30% of total assets this year.

Excluding incentives, NSTAR Electric's 2013 ROE was 11.11%. The utility's last rate settlement for 2006-2012 authorized a 10.5% ROE +/- 200 bps and we estimate that transmission assets are approximately 25%-30% of total assets this year.

In New Hampshire, Governor Maggie Hassan (D) enjoys a 10 point lead over challenger Walt Havenstein (R). We don't expect any significant changes to support for the Northern Pass transmission project, although we note that the candidates may be less talkative on the subject during the runnup to the election. NU continues to talk with property owners with existing lines along the proposed route.

NESCOE process slowed down by failed Massachusetts legislation; RFP after the elections?

We don't see any RFP possible before elections as both Massachusetts and RI will have new Governors (no incumbent running in either state). The New England States Committee on Electricity (NESCOE) had been expected to provide a schedule for its RFP by September for the development of transmission and delivery of at least 1.2-3.5 GW of clean energy into New England. However, this is now highly likely to be postponed through Nov/Dec as a result of the failure of Massachusetts to pass a Clean Energy Bill on July 31. The Bill would have allowed the state to enter into long-term contracts for ~19 TWhs of hydroelectricity from Hydro Quebec, essentially providing backstop financing for new power lines intended to be developed under a NESCOE RFP. Similar clean power procurement legislation already exists in Connecticut. Press reports indicated that environmental group opposition to hydropower in favor of wind and solar were a key factor in the Bill's demise. With no chance of any similar legislation this year, NESCOE's plan to file for two new tariffs to fund both electric transmission and new gas pipelines into New England have stalled as the states reconsider how to proceed – at least through this election cycle.

We don't see any RFP possible before elections as both Massachusetts and RI will have new Governors (no incumbent running in either state).

…But rising electric bills will keep up the pressure on states to act

Broadly speaking, utility rates in CT, MA and NH are probably going see energy rates rise from about $0.14 to $0.23-$0.24. CL&P's energy rate could rise to $0.13 with a total retail rate of about $0.225 (depends on the final CL&P rate order), and NSTAR's and WMECO's energy rate should rise to $0.14-$0.15, while Grid's Mass Elec will go to $0.162 with a total retail rate of $0.23-$0.245. We estimate that about 25% of New Hampshire customers (non-NU) will soon see their energy rate almost double to $0.15/kWh and their total retail rate jump from $0.15/kWh to $0.22/kWh. National Grid customers will likely see their energy rate rise to $0.13/kWh. In contrast, PSNH's energy rate (applicable to roughly 75% of all NH customers) will likely stay flattish at $0.09-$0.095 with a total retail rate of $0.17-$0.175/kWh due to its unique reliance on cheaper, ratebase coal, biomass, and hydro.

While not a political issue this season, we suspect it will be in 2015…

… Will NU be able to re-direct the heat towards infrastructure build and approvals?

NU Partnership with Spectra on Access Northeast pipeline not affected by election politics

NU and Spectra Energy (SE)'s proposed pipeline is unlikely to be affected by election season as the project is largely a replacement of pipe along existing routes. The companies announced a $3Bn, 1+bcf/day Access Northeast natural gas JV which designed to address New England gas bottlenecks. The project is a combination of additional pipeline capacity/expansions & storage facilities which will interconnect with Spectra's existing assets. NU & SE will be collecting solicitations of interest through Oct and will work with ISO-NE and NESCOE in Dec before beginning the FERC regulatory approval process next year. The project is not expected to be online until Nov '18 (earliest), leaving four winters before the true benefits of improved supply.

NU and SE take the lead, but lack of generation offtakers is the real issue

Previously National Grid and UIL were involved in the proposed NESCOE solution but now Spectra and NU will be equal partners in the project "with the option of additional investors joining in the future;" we still look for partners to come aboard with NU/SE jointly sharing the excess. NU may view the utilities as a "natural solution" to solving gas constraints but the issue still remains as to whether the Electric Distribution Companies can recover FERC-approved tariffs from electric retail customers, seeing generators as unable to fund upgrades. As SE management pointed out on the call, the market reforms are key to allow the recovery of cost of generation, with some potential for incremental gas LDC contracting. Reforms remain critical to projects materializing- and with NESCOE stalled – we sense a long road ahead for midstream gas developments.

Massachusetts natural gas distribution work set to accelerate significantly

At the February Analyst Day, NU forecasted $215M/yr of total natural gas distribution capex for the three years from 2015-2017. However, as a result of new Mass legislation, that projection is very likely to increase, perhaps by $150M-$160M for the period.

Accelerating the rate of conversions in Massachusetts would be a big boost for NU with residential gas penetration still below 50%.

Gas main replacement riders: New legislation in MA was passed in June to expedite the replacement of cast iron and unprotected bare steel gas distribution mains and to expand the state's natural gas distribution network over the next 20 years. The law provides for separate carve-out investment recovery mechanisms.

Once NSTAR Gas files its required expansion plan with the DPU, regulators will have 8 months to review and approve it.

Oil-to-gas conversion: The legislation also minimizes lag in oil-to-gas conversions and promote area gas charges that would help share costs of conversions and ultimately would be another catalyst towards the high-end of the long-term earnings growth rate for NU. The penetration for residential natural gas heating sits at 48% and 32% for MA and CT, respectively, far lower than that of neighboring New Jersey (72%), highlighting the scale of the opportunity here.

LNG Storage: NSTAR is working on a MA recovery mechanism for significant investment needed at its affiliate-owned 3.2 BCF Hopkinton LNG storage facility.

NSTAR Gas to file first ratecase in over 20 years: In May, NSTAR Gas notified the MA Department of Public Utilities (DPU) that it intends to file a ratecase before the end of the year (rates effective in 2016), the first case for them in more than 20 years.

Statement of Risk

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

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Neutral	FSR is between -6% and 6% of the MRA.	42%	28%
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Buy	Stock price expected to rise within three months from the time the rating was assigned because of a specific catalyst or event.	less than 1%	less than 1%
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Source: UBS. Rating allocations are as of 30 September 2014.
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Company Disclosures

Company Name	Reuters	12-month rating	Short-term rating	Price	Price date
AES Corporation[2, 4, 6a, 16]	AES.N	Neutral	N/A	US$13.73	24 Oct 2014
American Electric Power, Inc.[4, 5, 6b, 7, 16]	AEP.N	Neutral	N/A	US$56.47	24 Oct 2014
Calpine Corporation[2, 4, 6a, 16]	CPN.N	Neutral	N/A	US$21.96	24 Oct 2014
Consolidated Edison[6a, 16]	ED.N	Neutral	N/A	US$62.50	24 Oct 2014
DTE Energy Co.[2, 4, 6a, 16]	DTE.N	Neutral	N/A	US$80.20	24 Oct 2014
Duke Energy[2, 4, 6a, 16]	DUK.N	Buy	N/A	US$80.30	24 Oct 2014
Dynegy, Inc.[2, 4, 5, 16]	DYN.N	Buy	N/A	US$29.75	24 Oct 2014
Entergy Corp.[16]	ETR.N	Neutral	N/A	US$82.14	24 Oct 2014
FirstEnergy Corp.[16]	FE.N	Sell	N/A	US$36.27	24 Oct 2014
National Grid[2, 4, 5, 16]	NG.L	Neutral	N/A	891p	24 Oct 2014
NextEra Energy[2, 4, 6a, 16]	NEE.N	Buy	N/A	US$98.36	24 Oct 2014
NextEra Energy Partners LP[2, 4, 5, 6a, 16]	NEP.N	Neutral	N/A	US$34.67	24 Oct 2014
Northeast Utilities[6a, 13, 16]	NU.N	Buy	N/A	US$48.59	24 Oct 2014
NRG Energy Inc.[16]	NRG.N	Buy	N/A	US$29.72	24 Oct 2014
NRG Yield[16]	NYLD.N	Neutral	N/A	US$47.37	24 Oct 2014
Pinnacle West Capital Co.[2, 4, 6a, 16]	PNW.N	Buy	N/A	US$59.17	24 Oct 2014
TECO Energy Inc.[5, 16]	TE.N	Neutral	N/A	US$19.27	24 Oct 2014
Westar Energy, Inc.[4, 6a, 16]	WR.N	Neutral	N/A	US$36.79	24 Oct 2014
Wisconsin Energy Corp.[16]	WEC.N	Neutral	N/A	US$48.62	24 Oct 2014

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