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North America

Power and Utilities | Energy Efficiency

2014 Energy Policies Defined by Shift toward a Cleaner, More Reliable Grid

EPA's Clean Power Plan, Regional Efforts, and Continued Solar Installation Growth aim to Improve State-Level Resource Reliability

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Policy Brief

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Key Takeaways:

- The early impacts of EPA's proposed Clean Power Plan – together with regional reliability requirements – influenced energy mix shifts and infrastructure improvements
- Integrating renewables and distributed energy resources has challenged utility revenue streams and led to new business models and net energy metering designs
- In 2015 and beyond, regions and states will continue to explore the technical and economic aspects of increasing levels of distributed generation, with a focus on electric system reliability

Entities Mentioned:

- Arizona Corporation Commission
- Arizona Public Service
- California ISO
- Environmental Protection Agency
- Federal Energy Regulatory Commission
- Hawaii Public Utilities Commission
- Hawaiian Electric Companies
- New England ISO
- PJM Interconnection

Related Research

EPA Rule Flexible, Yet Tough For Some Coal-Reliant States

Utilities Nationwide Adjust Rate Designs to Meet Changing Customer Demand

Economics and Regulations Support Energy Mix Shift

An aging fleet of coal-fired generation exposed to the Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards and continued economic displacement by natural gas-fired capacity will force approximately 50 to 60 gigawatts (GW) of domestic coal-fired capacity to retire (from 2010 levels) prior to 2017. Although coal-fired plant economics recovered slightly in 2014, efficiency and emissions reduction investments will continue as the EPA finalizes new regulations for existing sources in the coming year.

50 to 60 GW of coal-fired capacity will retire prior to 2017

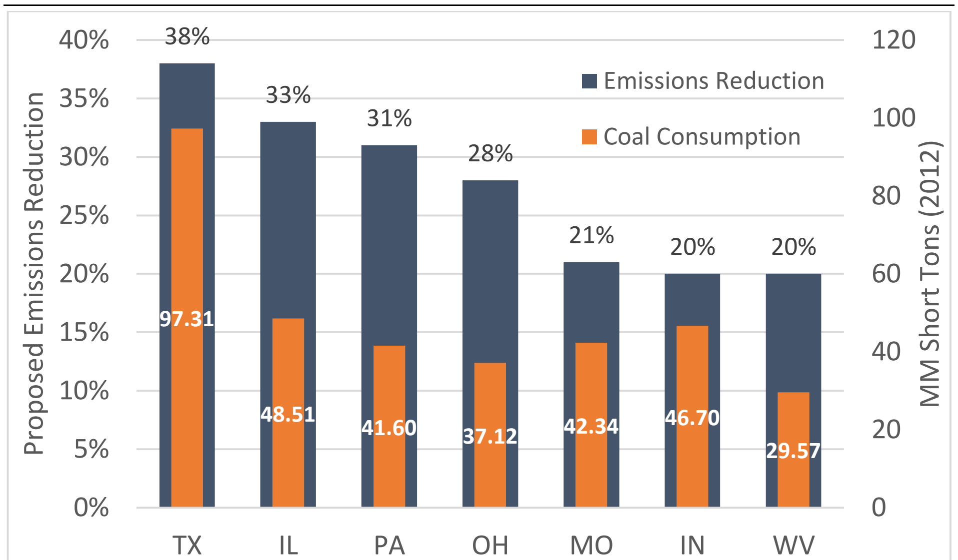
Domestic energy resource diversity growth and how to best support and incorporate those new, often distributed resources onto the grid is a key trend emerging from 2014. Regions and states are working to redesign – from a regulatory to technical level – how generators, load-serving entities, and customers interact to ensure an efficient, reliable electricity grid.

EPA Proposes Landmark Emissions Regulations

In addition to existing rules, the EPA's Clean Power Plan proposal is by far the agency's biggest action of 2014. The CPP was unveiled on June 2 and could set state-specific rate- or mass-based emissions reduction levels – from existing generators – to reach a 30 percent nationwide emissions reduction from 2005 levels by 2030. The proposed plan has the potential to significantly impact coal-reliant states (Figure 1) with ripple impacts across all energy sectors. Texas leads the nation in coal consumption, but its access to natural gas and wind power will help ease future compliance obligations. More coal-reliant states without easily-accessible natural gas or renewable energy sources – such as Missouri and West Virginia – may find compliance more difficult.

The Clean Power Plan is EPA's biggest action of 2014 and would significantly impact coal-reliant states

Figure 1 – Select State Emissions Reduction Goals and 2012 Coal Consumption



Source: EnerKnol analysis of EPA and EIA data

Final EPA CPP construct and market impact is still uncertain as state and industry pushback mounts. Twelve states – Alabama, Indiana, Kansas, Kentucky, Louisiana, Nebraska, Ohio, Oklahoma, South Carolina, South Dakota, West Virginia, and Wyoming – and the nation's largest private coal mining company – Murray Energy – have already opened suit against EPA. Opposition is likely to continue as EPA aims to finalize the CPP in June 2015, which could delay – or threaten as a whole – program implementation well-beyond 2015.

State litigation and Republican-controlled Congress could impact CPP implementation

The new Republican-controlled Congress could also impact the CPP implementation timeline. Following a November North American Electric Reliability Corporation (NERC) report on potential CPP impacts, Senate and House republicans – Sen. Lisa Murkowski (R-AK), Rep. Fred Upton (R-MI), and Rep. Ed Whitfield (R-KY) – requested that by January 12, each FERC commissioner describe "the extent of consultation and coordination" with EPA on CPP development, and that FERC hold a technical conference to "examine the significant concerns" identified in the NERC report. FERC will hold four technical conferences on the CPP, starting February 19 in Washington D.C. Ultimately, any lasting opposition to the CPP will come from the states.

States Addressing Evolving Energy Mix

NY leads the nation in 2014 with its Reforming the Energy Vision proceeding

Notwithstanding the controversy over the federal Clean Power Plan, state policies and continued technological advancements are facilitating a significant shift from traditional power generation and distribution to increased levels of distributed energy resources (DERs). New York's Reforming the Energy Vision (REV) proceeding is 2014's most comprehensive state effort toward a more efficient and reliable electric grid. REV aims to move the state's energy sector towards a decentralized, market-based structure with increased customer interaction through outreach and technology. Key program design topics include, but are not limited to, the utilities' role in the proposed "distributed system platform provider" model, and whether or not utilities will be permitted to own and operate DERs in the future.

In April, the Hawaii Public Utilities Commission (PUC) ordered the Hawaiian Electric Companies (HECO) to create a plan to reduce energy costs and address renewable energy integration challenges. The PUC offered guidance in its "Commission's Inclinations on the Future of Hawaii's Electric Utilities" whitepaper, and in August, HECO submitted an ambitious plan to reduce electricity bills by 20 percent, and procure more than 65 percent of the companies' energy from renewable energy sources by 2030. The PUC is currently evaluating the filings. In addition, HECO has partnered with the National Renewable Energy Laboratory (NREL) and SolarCity to study grid operation implications of high distributed solar PV penetration.

In August, the California PUC instituted a Distributed Resources Plan (DRP) – R.14-08-013 – to prepare for and understand the impacts of increased DER integration in the state's grid system. This is particularly important for California, as the state is leading in residential solar energy output and recently announced an energy storage goal of 1.3 GW by 2020. The DRP incorporates more than 10 individual rulemakings, with final rulemaking guidance expected by February 2, 2015.

Increasing Distributed Generation Levels Force Rate Design Reform

Integration of renewables and other DERs, increasing energy efficiency, and new end-use energy management solutions are challenging utility revenue streams, which are fundamentally tied to volumetric energy sales. In addition to a shifting business model, utilities are also faced with rising transmission and distribution (T&D) costs with growing peak demand, but flattening overall (kilowatt-hour) energy demand. As customers in some states continue to add on-site generation, utilities are challenged to re-design rate structures to maintain return on equity, while also ensuring grid stability with increasing levels of two-way power flow through net energy metering (NEM).

CA's high levels of distributed generation creates a unique regulatory and system challenge

California's AB 327 went into effect on January 1 of this year. The law now permits utilities to implement up to a $10 per customer – and $5 per low-income "CARE" program customer – fixed charge starting on January 1, 2015. In addition, AB 327 calls for the PUC to develop a NEM successor tariff that supports sustainable customer-sited generation growth, including disadvantaged communities; is based on the costs and benefits of each facility; allows projects greater than 1 MW to interconnect with reasonable charges; and establishes terms of service and billing consistent with relevant statutory requirements. The new tariff draft is due by December 31, 2015 and will be implemented on either July 1, 2017, or when the state reaches its 5 percent NEM cap. With a more robust benefit-cost analysis of customer-sited DG, the NEM-successor might look similar to Minnesota's new Value of Solar Tariff (VOST), which considers ten avoided costs to determine a surplus power compensation rate (Figure 2).

Figure 2 – Example VOST Calculation Chart

25-Year Levelized Value	Economic Value ($/kWh)	Load Match (No Losses) (%)	Distribution Loss Savings (%)	Distributed PV Value ($/kWh)
Avoided Fuel Cost	$ 0.056		8%	$ 0.061
Avoided Plant O&M - Fixed	$ 0.003	40%	9%	$ 0.001
Avoided Plant O&M - Variable	$ 0.001		8%	$ 0.001
Avoided Gen Capacity Cost	$ 0.048	40%	9%	$ 0.021
Avoided Reserve Capacity Cost	$ 0.007	40%	9%	$ 0.003
Avoided Trans. Capacity Cost	$ 0.018	40%	9%	$ 0.008
Avoided Dist. Capacity Cost	$ 0.008	30%	5%	$ 0.003
Avoided Environmental Cost	$ 0.027		8%	$ 0.029
Avoided Voltage Control Cost				
Avoided Solar Integration Cost				
				$ 0.127

Source: Minnesota Department of Commerce

In recent years, Arizona utilities have explored methods of mitigating the impacts of increasing residential solar installations. The Arizona Corporation Commission (ACC) approved a fixed fee of $0.70 per kW for Arizona Public Service (APS) customers with rooftop solar installations, effective January 1 of this year. To meet state Renewable Portfolio Standards (RPS), APS requested approval to own 20 MW of solar installations on 3,000 – essentially rented – customer home rooftops for a $30 per month bill credit. Citing high costs, the ACC staff recommended commissioners reject the request, in addition to rejecting APS' proposed 20 MW Redhawk Power Station. However, on December 19 the ACC voted it would not oppose a lower-capacity APS proposal to own 10 MW of residential rooftop solar at the $30 per month bill credit rate. A day earlier, the ACC approved a Tucson Electric Power proposal to own 3.5 MW of solar power on 600 residents' rooftops for a $250 up-front charge and 25-year set rate based on their average historical energy use.

Utilities will continue to push for fixed cost increases as solar installations proliferate

Wisconsin Utilities Raise Fixed Charges despite Few Solar Installations

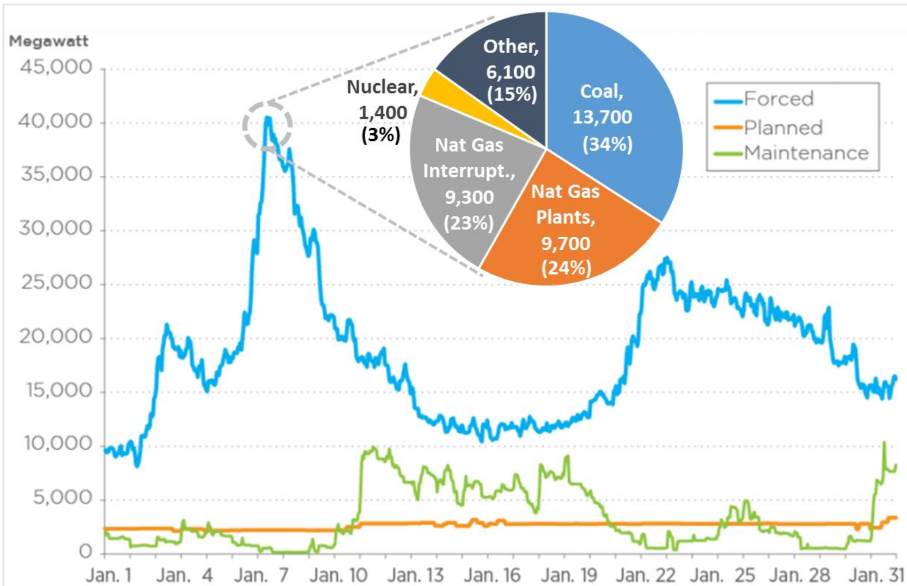
On January 31, Wisconsin's Madison Gas & Electric (MG&E) and Wisconsin Electric Power Company (WE Energies) requested significant fixed charge increases for their customers, accompanied by a reduced energy charge. The proposals are in an effort to better cover infrastructure costs in a manner not directly tied to energy sales. In November, the Wisconsin Public Service Commission (PSC) approved fixed charge increases for all MG&E and WE Energies residential customers. In 2015, the monthly fixed charge for MG&E customers rises from approximately $10 to $19, and WE Energies customers' fixed charge will rise from approximately $9 to $16 per month.

Capacity Market Reforms and Winter Reliability Programs Address Regional Resource Performance

The 2013-2014 winter polar vortex and cold-snap events caused record forced generation capacity outages in the PJM Interconnection (PJM) and New England ISO (ISO-NE) regions, prompting the ISOs to implement new market structures to ensure future reliability. Forced outage levels in the PJM region reached a high of approximately 40,200 megawatts (MW) on January 7, representing nearly 22 percent of the region's total generation capacity (Figure 3). The high outage levels from committed generation capacity prompted PJM to reassess its capacity product definitions and associated performance incentives and penalties. Lack of firm natural gas pipeline supply was a common cause of generator outages during last winter's extreme winter events in the PJM and ISO-NE regions. With increasing emphasis on system reliability, new Forward Capacity Market (FCM) market designs could incent pipeline and gas-fired generator build-out through improved capacity performance incentives.

Regional capacity market reforms will improve future system reliability

Figure 3 – January 2014 PJM Forced Winter Outages (MW)



Source: EnerKnol analysis of PJM data

ISO-NE implemented its first Winter Reliability Program (WRP) in October 2013 to ensure system reliability during winter peak demand, in part due to lagging new natural gas pipeline construction. The program proved beneficial, and this winter's ISO-NE WRP provides incentives for increased oil-fired generator inventory, demand response, dual-fuel capability, and LNG import contracts. While northeast natural gas pipeline projects continue to lag behind winter demand, the region is expected to get partial relief in November 2016 through Spectra Energy's Algonquin Incremental Market (AIM) pipeline, with more significant pipeline additions expected in 2018.

The ISO-NE WRP is a temporary solution prior to new regional pipeline construction

Similar to PJM, ISO-NE proposed – originally in 2012 – to more closely link capacity resource payments with performance, with an aim to increase FCM resource reliability. The FERC largely approved the new ISO-NE proposal in May, which will compensate resources both for committed capacity and provide payments or penalties depending on actual energy delivery, starting with the 2018/2019 deliver period. PJM has used the approved ISO-NE FCM reforms to form its proposed capacity market non-performance penalty calculations.

Looking Ahead to 2015

The regulatory and economic shift towards a cleaner, more distributed, and more reliable grid will necessitate continued reforms at all levels of the energy sector. In particular, the continuation of several policies initiated in 2014 will influence utilities and technologies in 2015.

The EPA aims to finalize its proposed Clean Power Plan in June 2015. However, this deadline is uncertain, as the agency has already experienced significant state and industry pushback and litigation, and received more than 1.6 million comments in total through its extended comment period. If the EPA does meet its June 2015 target, implementation will likely be delayed by litigation to defund the EPA or overturn the rule, which would be supported by the Republican-led Congress but filibustered by Democrats in the Senate.

Although not discussed in this report, the pending vacatur of FERC Order 745 in May – and its ongoing uncertainty – could significantly impact demand response markets.

California, Hawaii, and New York will continue efforts that began in 2014 to move to a new electric grid model that supports increasing levels of distributed generation. These efforts will be matched by utilities across many states reconsidering traditional rate structures based on volumetric energy sales, as well as new net energy metering designs to better consider all costs and benefits of distributed solar.

The PJM Capacity Performance proposal is pending FERC approval and will be finalized in 2015. PJM has requested approval by April 1 in an effort to incorporate the reforms in its May Base Residual Auction for the 2018/2019 delivery year. The reforms would be phased-in but would result in elevated auction settlement prices in the May auction, if approved in time.

The success of the new ISO-NE Winter Reliability Program will be largely dictated by the severity and duration of this winter's "cold-snap" events. The region's pipeline capacity additions and new Forward Capacity Market design will not significantly address reliability issues until late 2016 and 2018, respectively.

Disclosures Section

RESEARCH RISKS

Regulatory and Legislative agendas are subject to change.

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