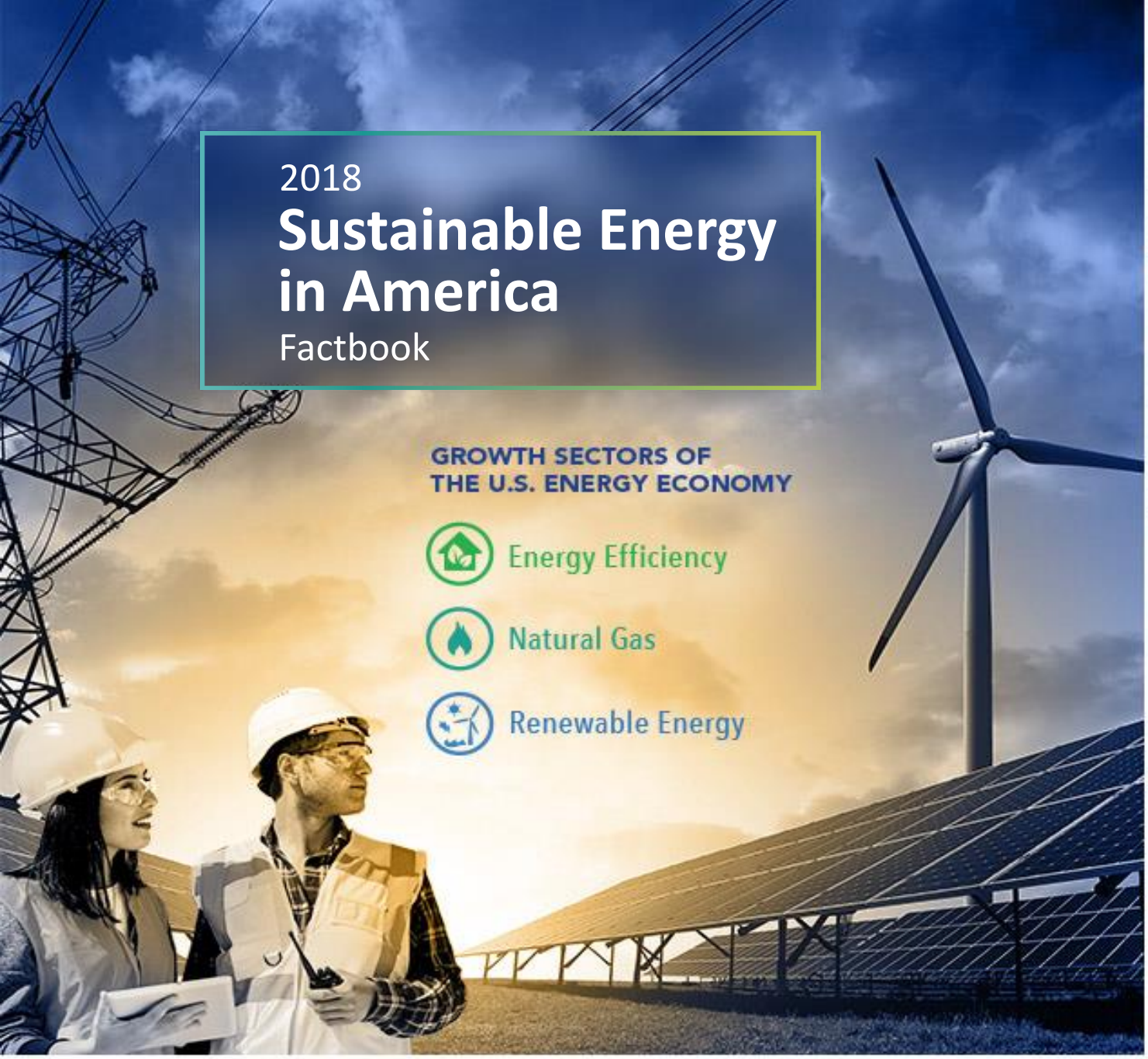
2018

Sustainable Energy in America

Factbook



Bloomberg New Energy Finance

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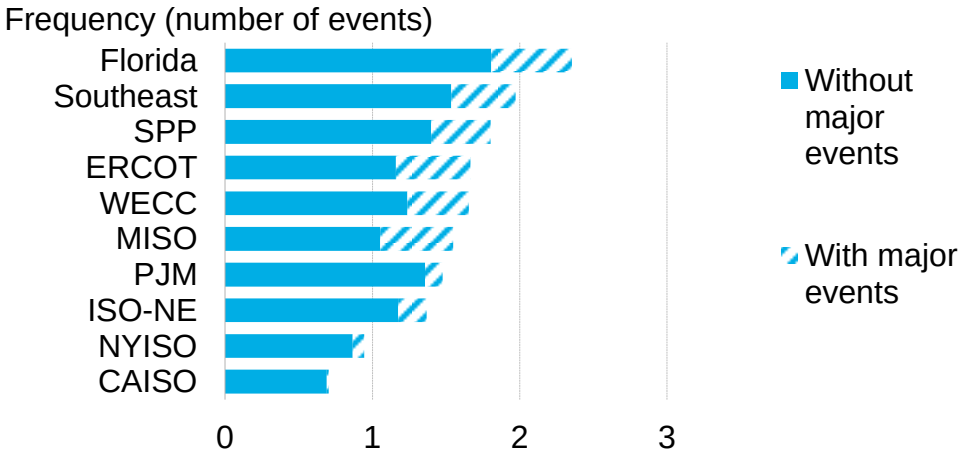
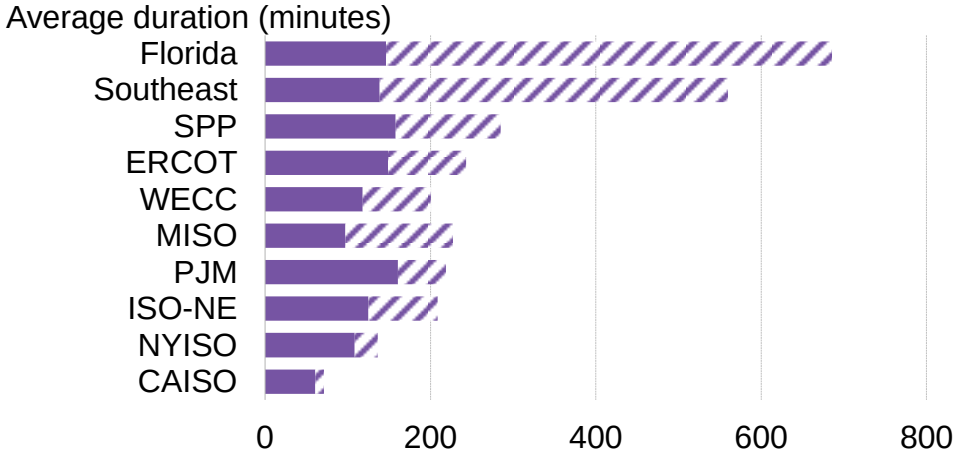
Policy (2 of 5): Department of Energy grid study on reliability and resilience

Average frequency of electric power service interruptions per customer (2016)



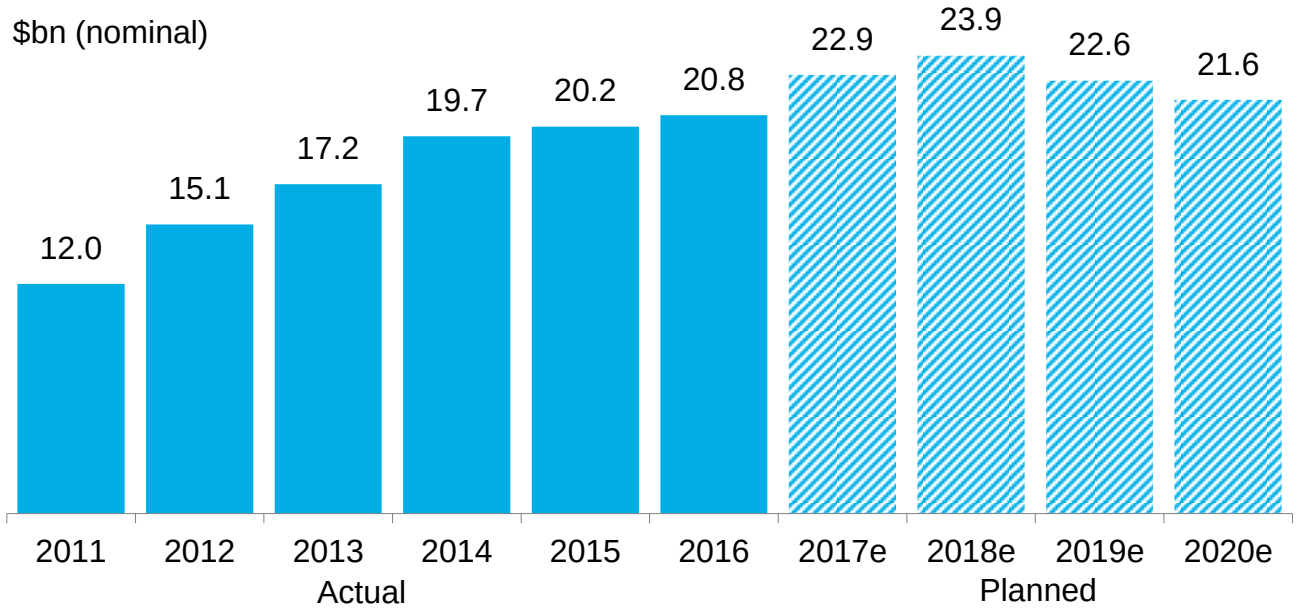
Average duration of electric power service interruption (2016)



- In August 2017, the Department of Energy issued a grid study concluding that generators capable of providing "essential reliability services," as well as resilience, to the grid should be compensated for these services. On the back of the report, Energy Secretary Rick Perry asked the Federal Energy Regulatory Commission (FERC) to launch an expedited rulemaking to provide cost recovery for "secure fuel" generators with 90-day fuel supplies on hand. Most coal and nuclear facilities meet that criterion; wind, solar and natural gas plants do not. The rule focused on plants in competitive wholesale power markets, as opposed to regulated power regions such as the Southeast.
- In January 2018, FERC refused to proceed with such a rulemaking, finding insufficient evidence that either on-hand fuel supplies or other criteria presented by Perry were satisfactory indicators of resilience. Instead, it asked regional grid operators to examine resilience within their systems.
- The Department of Energy grid study had noted that wholesale power markets have, to date, ensured reliability, despite pressures created by growing natural gas penetration, flat demand, and policy interventions (including renewables support); however, the study also questioned whether the grid would remain resilient in the face of future challenges.
- EIA power outage data suggest that two regulated power regions, Florida and the Southeast, topped 2016's list in terms of the frequency of outage events (a measure of grid reliability). This is the case both when accounting for and when excluding the impact of major disruptive events (e.g., weather-related events such as hurricanes or heatwaves, and man-made disruptions such as cyber attacks). SPP and ERCOT ranked third and fourth, respectively, when accounting for major events.
- Florida and the Southeast also topped the list in terms of the average duration of outages during major disruptive events. This is likely driven by the greater impact of hurricanes on these two regions compared to the rest of the U.S. Removing major events, PJM and SPP endured the longest average outages (around 160 minutes).
- A number of factors, including customer density, the length of power lines, the makeup of the fleet, tree density, and how utilities define "major events" can all affect these measures of how frequently each region experiences outages, and how long they last.

Source: EIA, IEEE, BNEF

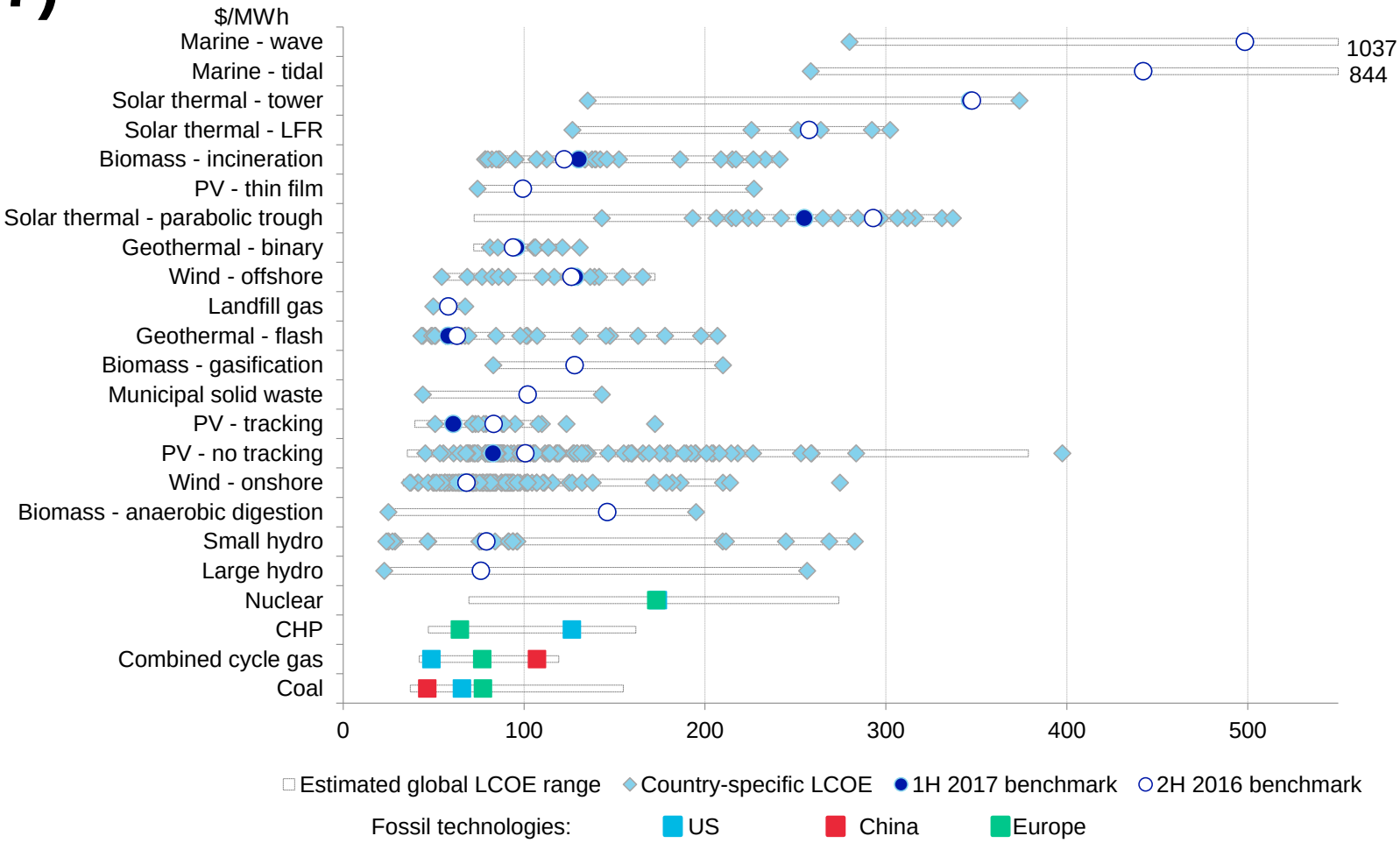
Finance: U.S. transmission investment by investor-owned utilities and independent transmission developers



- Investor-owned utilities and independent transmission developers spent an estimated $20.8 billion on electric transmission in 2016, a new high. This is up 3% from 2015.
- Based on company reports, investor presentations and a survey conducted by the Edison Electric Institute (EEI), transmission investment is likely to grow 10% in 2017 to $22.9 billion. Current capex plans suggest that investment will peak at $23.9bn in 2018; however, because 2018-2019 budgets are not yet finalized, these numbers may be revised upwards.
- The upswing in transmission investment is motivated by a number of factors, all of which concern the utility's fundamental aim of providing reliable, affordable, and safe power. These include a need to replace and upgrade aging power lines, resiliency planning in response to potential threats (both natural and man-made), the integration of renewable resources, and congestion reduction.

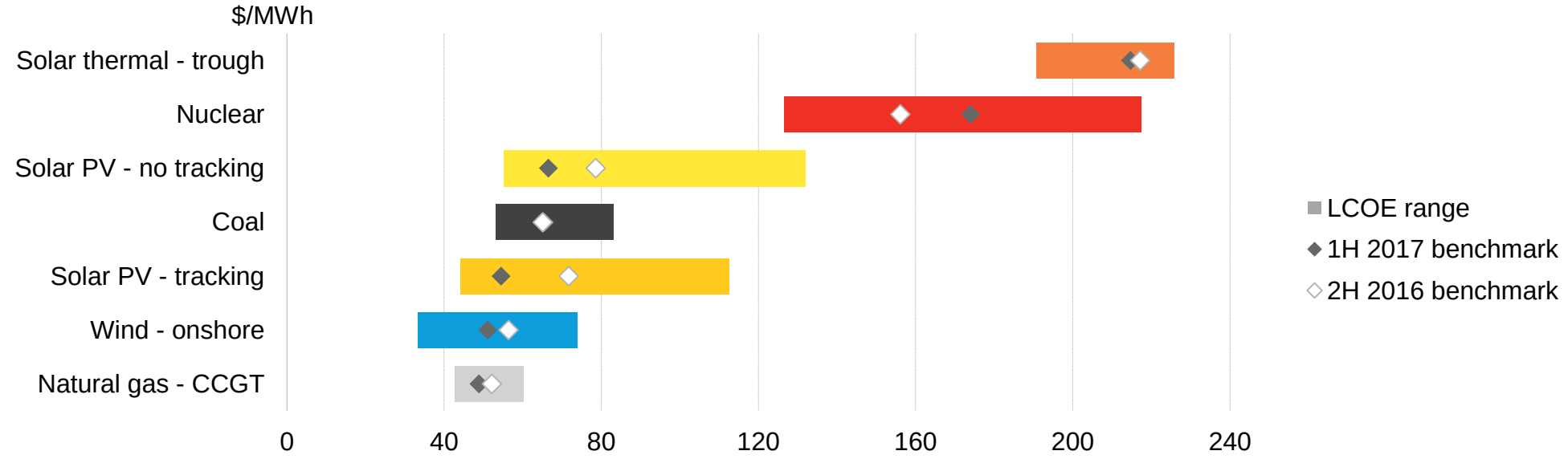
Source: Edison Electric Institute (updated September 2017)

Economics: Global levelized costs of electricity (unsubsidized for new build, 1H 2017)



Source: Bloomberg New Energy Finance Notes: LCOEs do not account for the impact of the 2017 tax reform in the U.S. LCOE is the per-MWh inflation-adjusted lifecycle cost of producing electricity from a technology assuming a certain hurdle rate (i.e., after-tax, equity internal rate of return, or IRR). The target IRR used for this analysis is 10% across all technologies. All figures are derived from Bloomberg New Energy Finance analysis, based on numbers derived from actual deals (for inputs pertaining to capital costs per MW) and from interviews with industry participants (for inputs such as debt/equity mix, cost of debt, operating costs, and typical project performance). Capital costs are based on evidence from actual deals, which may or may not have yielded a margin to the sellers of the equipment; the only 'margin' that is assumed for this analysis is 10% after-tax equity IRR for the project sponsor. The diamonds correspond to the costs of actual projects from regions all over the world; the hollow circles correspond to "global central scenarios" (these central scenarios are made up of a blend of inputs from competitive projects in mature markets). For nuclear, gas, and coal, the light blue squares correspond to U.S.-specific scenarios. "CHP"" stands for combined heat and power; "LFR" stands for linear Fresnel reflector. EIA is the source for capex ranges for nuclear and conventional plants.

Economics: U.S. levelized costs of electricity (unsubsidized for new build, 1H 2017)

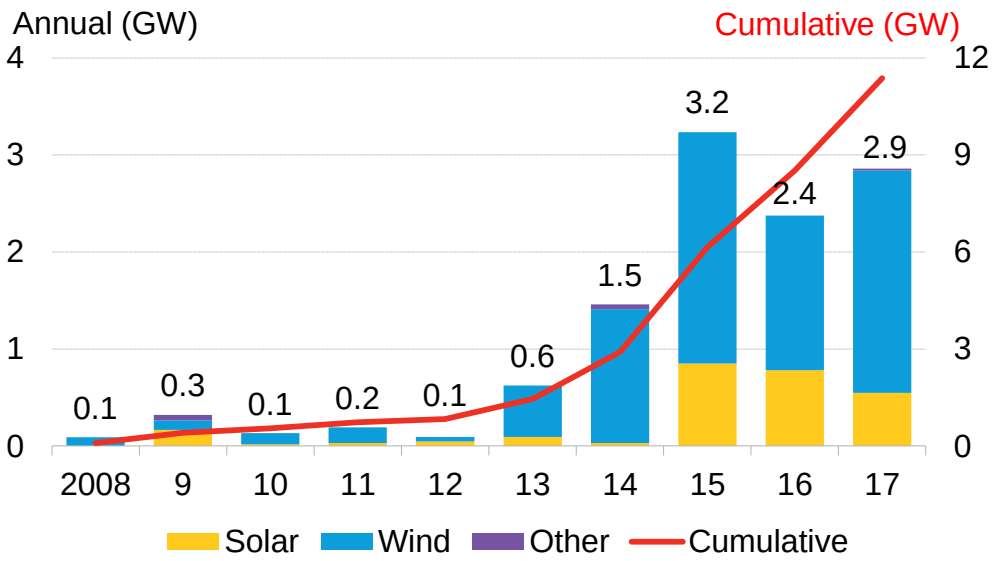


- New solar PV plants can now undercut new coal build on a levelized cost of energy (LCOE) basis in the U.S. The benchmark LCOE for a solar system with tracking was estimated at $54/MWh for 1H 2017, whereas coal came in at $66/MWh. Capex reductions drove a $17/MWh drop in the levelized cost estimate for solar with tracking since 2H 2016.
- Meanwhile, growing renewable energy penetration and coal-to-gas switching continue to limit the average capacity factor expected for new coal-fired power plants, helping to limit any levelized cost reductions.
- Combined-cycle gas remains one of the cheapest sources of new generation in the U.S., with benchmark projects achieving levelized costs of $49/MWh.
- New onshore wind projects constructed in areas with strong wind resources can achieve LCOEs as low as $33/MWh, beating out even cheap natural gas build.

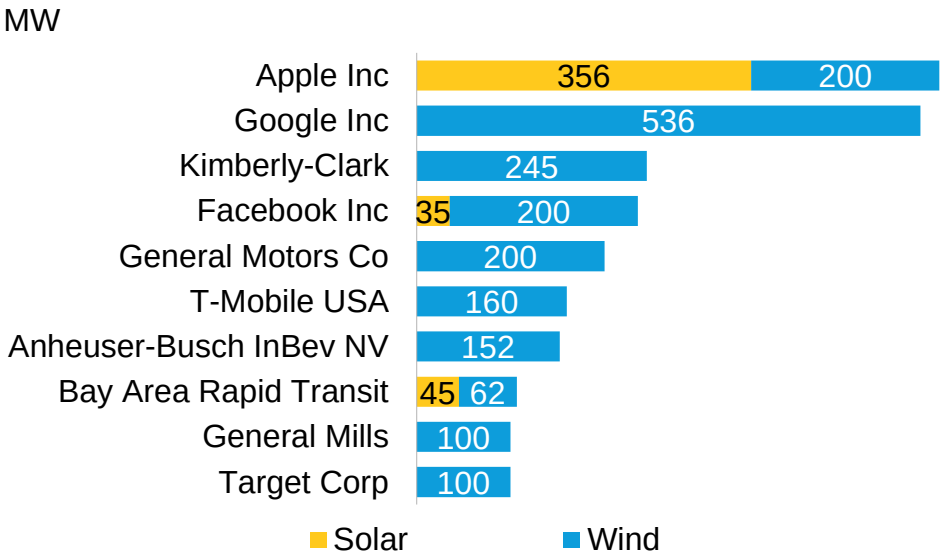
Source: Bloomberg New Energy Finance Note: LCOEs do not account for the impact of the tax reform in the U.S. "CCGT" stands for combined cycle gas turbine. See previous slide for further notes regarding methodology.

Finance: Corporate procurement of clean energy in the U.S.

Renewable capacity contracted by corporations, by technology



Largest corporate offtakers, 2017

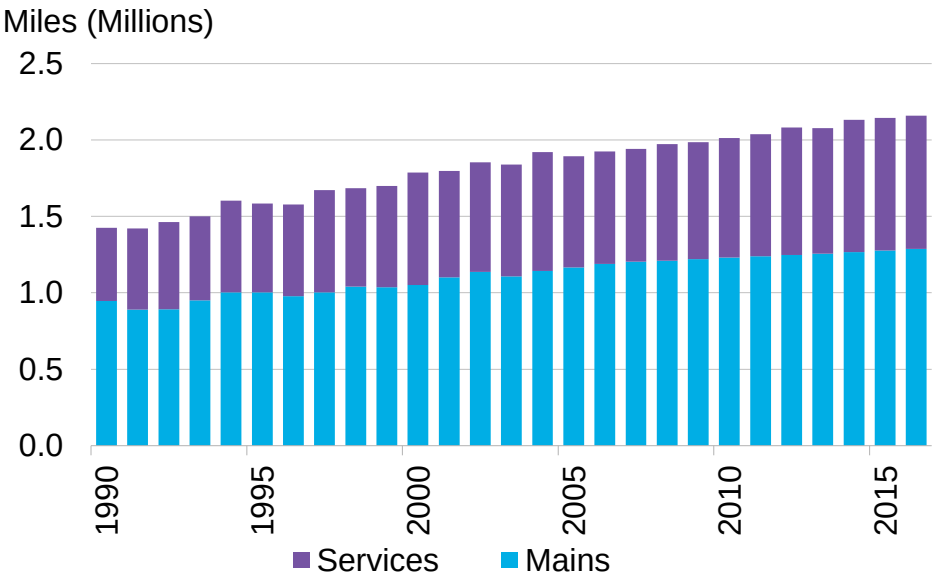


- Corporate PPA volumes rose to 2.9GW in 2017, up from the 2.4GW signed in 2016. Sustainability continues to drive activity in the U.S., although many large corporations have met their medial targets domestically and are now looking to sign deals internationally.
- Power prices continue to remain low across the U.S., and are further depressed during hours of high wind in markets like ERCOT and SPP, and when solar generates in CAISO. This has left many PPAs underwater, and corporations are now targeting wholesale markets with lower existing renewable penetration, like MISO and PJM.
- Apple contracted 0.56GW of U.S. clean energy in 2017, more than any other corporation. It signed the largest PPA ever in the U.S. between a corporation and a utility – a 235MW PV plant with NV Energy under the utility's GreenEnergy Rider. Google signed PPAs for 0.54GW, en route to offsetting 100% of its global electricity demand. Kimberly-Clark, T-Mobile, General Mills and Cummins all signed their first PPAs in 2017.
- Green tariff programs made up 19% of corporate procurement activity in 2017, as companies are increasingly looking to source clean energy within the same service territory as their load. These programs are offered by utilities in 12 states, with one more state pending.

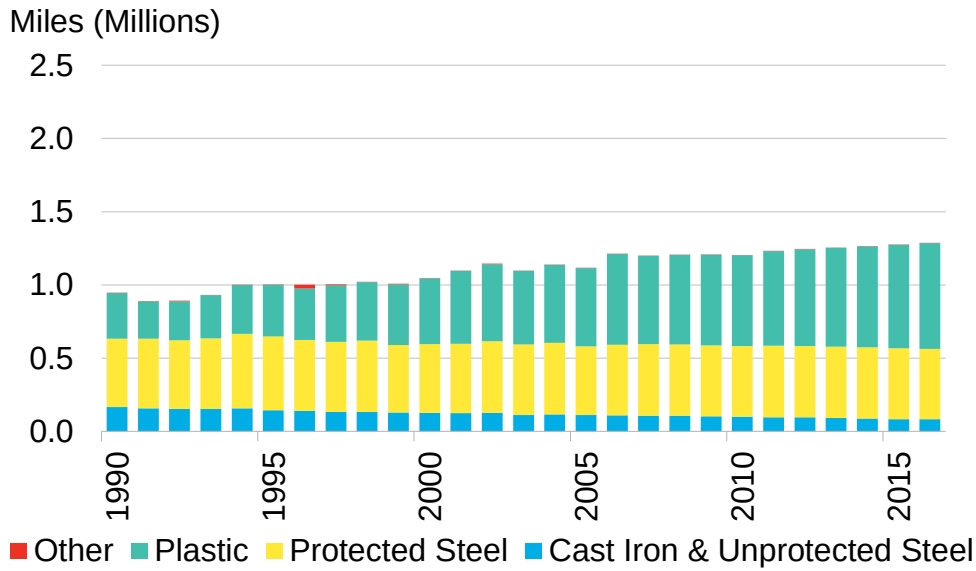
Source: Bloomberg New Energy Finance Note: Charts show offsite PPAs only

Deployment: U.S. natural gas pipeline installations and materials

U.S. existing natural gas distribution pipelines



U.S. natural gas distribution mainline material

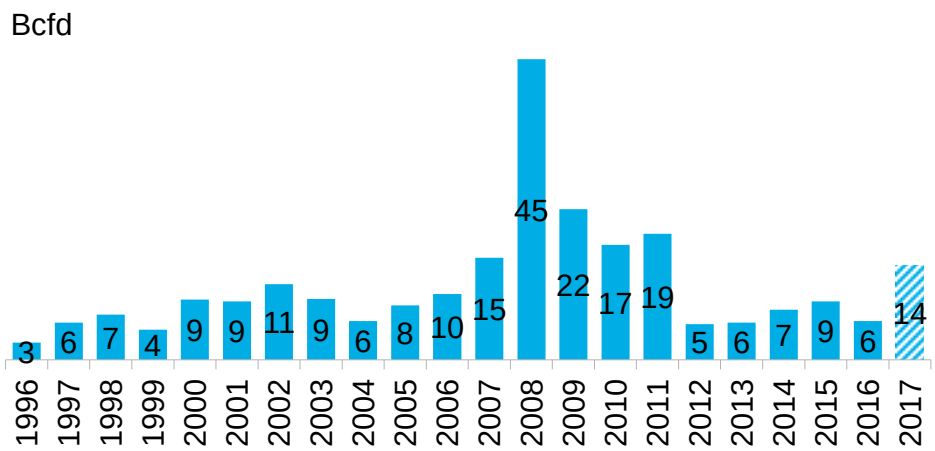


- Service and distribution pipelines that bring gas from transmission lines to end-users continue to develop incrementally, with growth averaging 1% per year over the past decade.
- Plastic is the material of choice for replacement and expansion efforts as U.S. pipelines are upgraded with more modern materials. Companies are removing older networks, which are made from cast iron and unprotected steel, and replacing them with newer plastic / protected steel pipes that are less susceptible to leaks. At the same time, more miles of pipeline are being added to connect underserved and previously unserved customers.

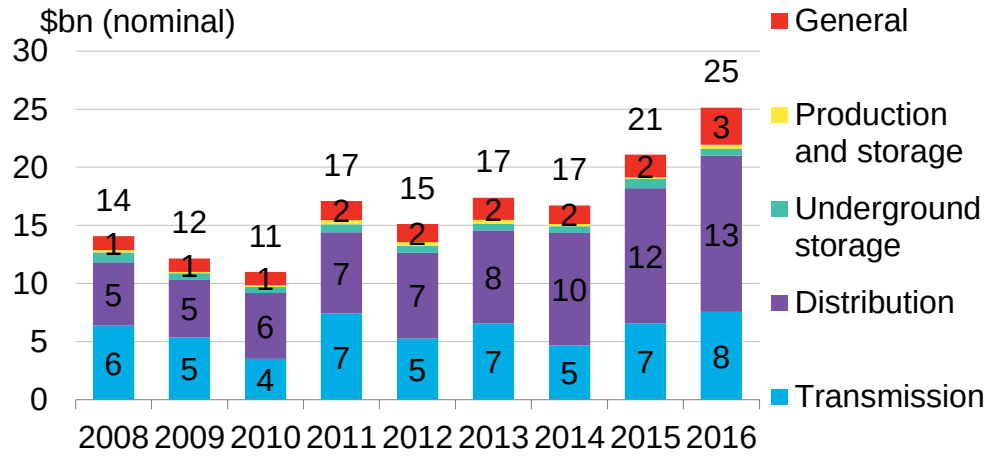
Source: American Gas Association, U.S. Department of Transportation

Deployment: U.S. midstream infrastructure capacity and investment

U.S. transmission pipeline capacity additions



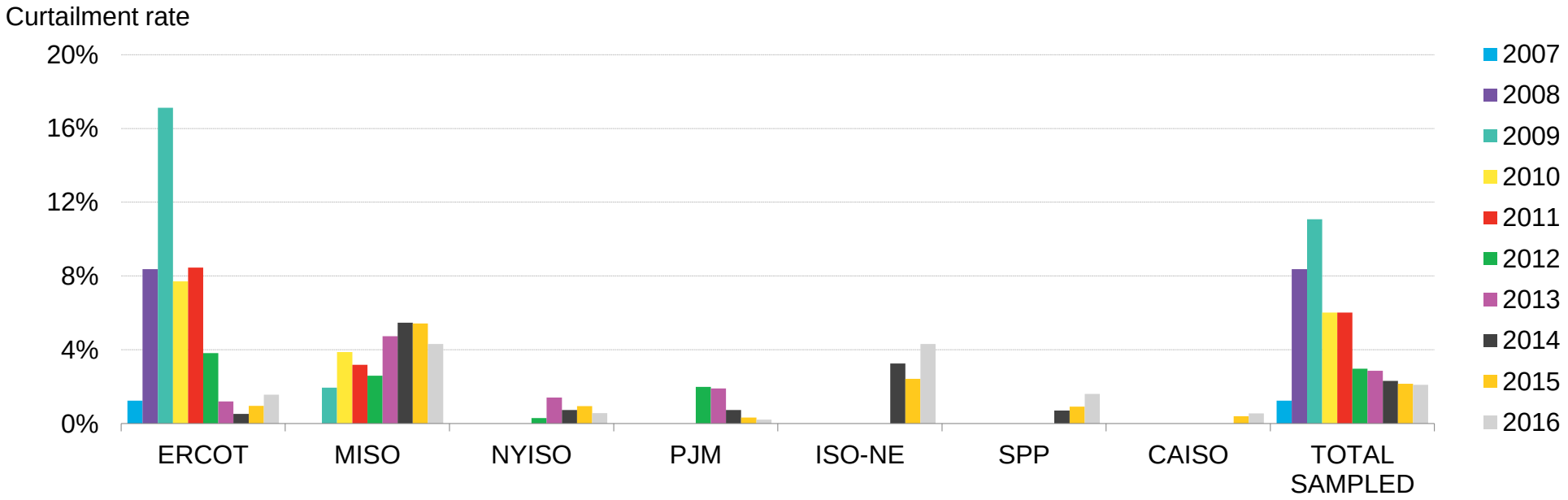
U.S. midstream gas construction expenditures



- Pipeline companies completed 6Bcfd of pipeline capacity in 2016, just slightly below the 7.6Bcfd planned. A number of delays pushed the online date of many substantial projects from 2015-2016 into 2017-2018.
- The next few years are scheduled to see major increases in pipeline capacity growth. 33Bcfd of capacity was scheduled to be completed in 2017, though just under half of this is estimated to have been complete by year's end.
- Takeaway capacity from the Appalachian Basin expanded by 4.1Bcfd in 2017, but only 0.04Bcfd (1%) of this brings gas into New England (through the Atlantic Bridge Expansion project on the Algonquin pipeline). As a result, natural gas delivery into New England remains constrained.
- Midstream expenditures increased 19% year-on-year in 2016. Distribution accounted for nearly half of the increased spending, rising to its highest level yet at $13.4bn, a 16% increase over 2015 levels. There was also a small but noticeable increase in production and storage expenditure, which more than doubled in 2016.

Source: Bloomberg New Energy Finance, American Gas Association, EIA Notes: EIA data used here include both first-mile takeaway capacity and other pipeline additions that do not impact takeaway capacity. 2017 transmission capacity addition is a BNEF estimate and not EIA historical data. Expenditure values reflect figures reported to the AGA by different types of companies across the supply chain, including transmission companies, investor-owned local distribution companies, and municipal gas utilities. "General'" includes miscellaneous expenditures such as construction of administrative buildings. Totals may not sum due to rounding.

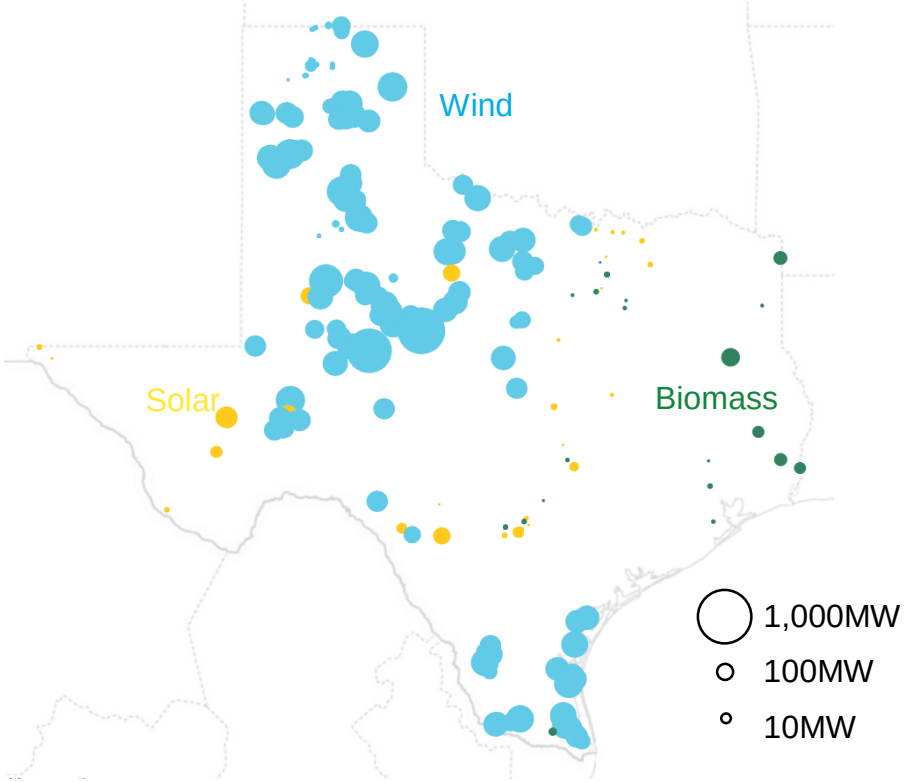
Deployment: U.S. wind curtailment

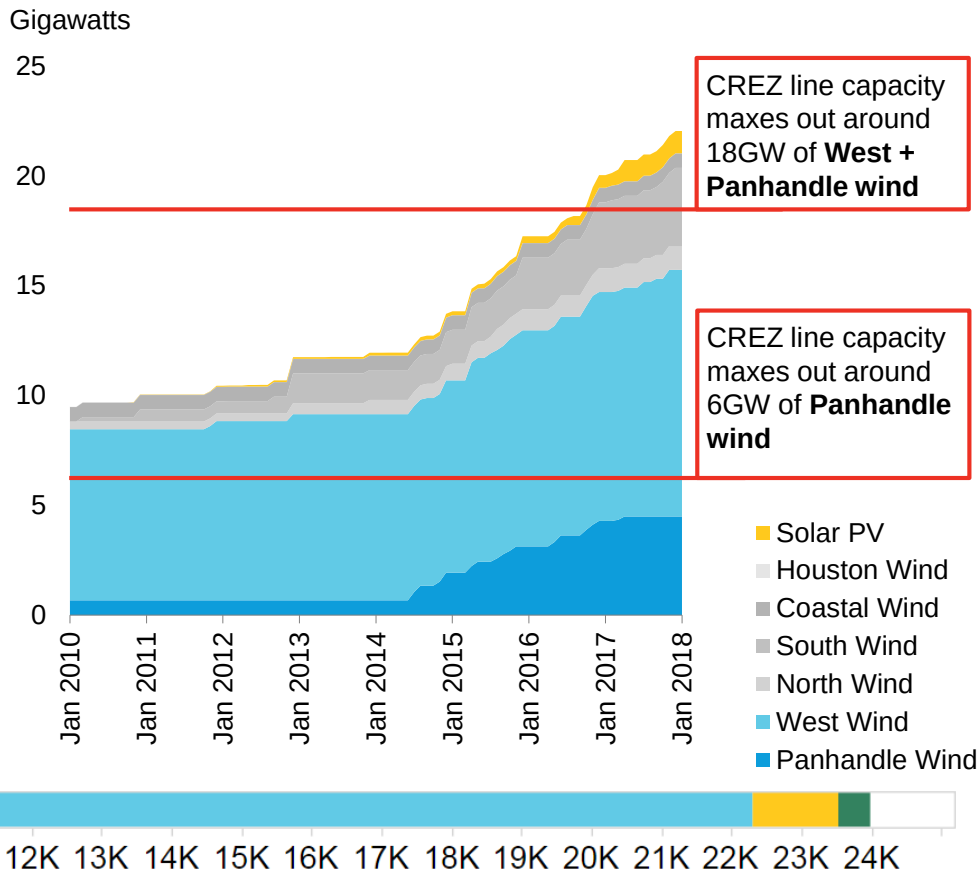


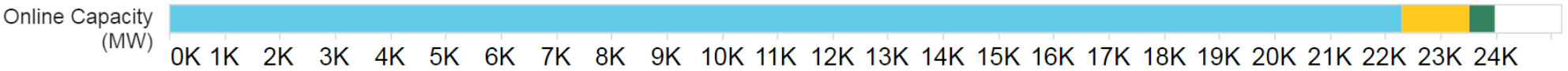
- Curtailment can occur due to transmission constraints, inflexibilities in the grid and environmental or generation restrictions.
- This was a significant problem in ERCOT (Texas) from 2008-2013, but the build-out and upgrade of the Competitive Renewable Energy Zone (CREZ) transmission lines and increased efficiency in ERCOT's wholesale electricity market lessened this concern. Curtailment in this region fell to only 0.5% in 2014, down from a peak of 17% in 2009. It stayed just under 1% for 2015, but ticked back up to 2% for 2016.
- In both 2015 and 2016, PJM experienced the lowest curtailment of any region, at 0.2%. MISO and New England continued to experience curtailment rates of over 4%, the highest out of all the regions sampled. However, MISO's wind curtailment dropped 21% from 2015 to 2016, as transmission build began to alleviate congestion; most of MISO's MVP transmission projects should be online by 2019. New England's curtailment levels in 2016 jumped 78% from 2015, an issue that needs to be addressed for Massachusetts to reach its 50% Renewable Portfolio Standard. CAISO, NYISO, and SPP fall in the middle, experiencing 0.5%, 0.6% and 1.61% of curtailment, respectively.
- Total U.S. curtailment has shrunk since 2009. However, time-varying influences also played a role: in 2015, for example, the western and interior U.S. experienced below-normal wind speeds, reducing generation and therefore the need to curtail in constrained regions.

Source: Bloomberg New Energy Finance, Department of Energy. Note: All curtailment percentages shown in the figure represent both forced and economic curtailment. PJM's 2012 curtailment estimate is for June through December only. Department of Energy sourced data from ERCOT, MISO, CAISO, NYISO, PJM, ISO-NE, SPP.

Deployment: ERCOT's Competitive Renewable Energy Zone (CREZ)





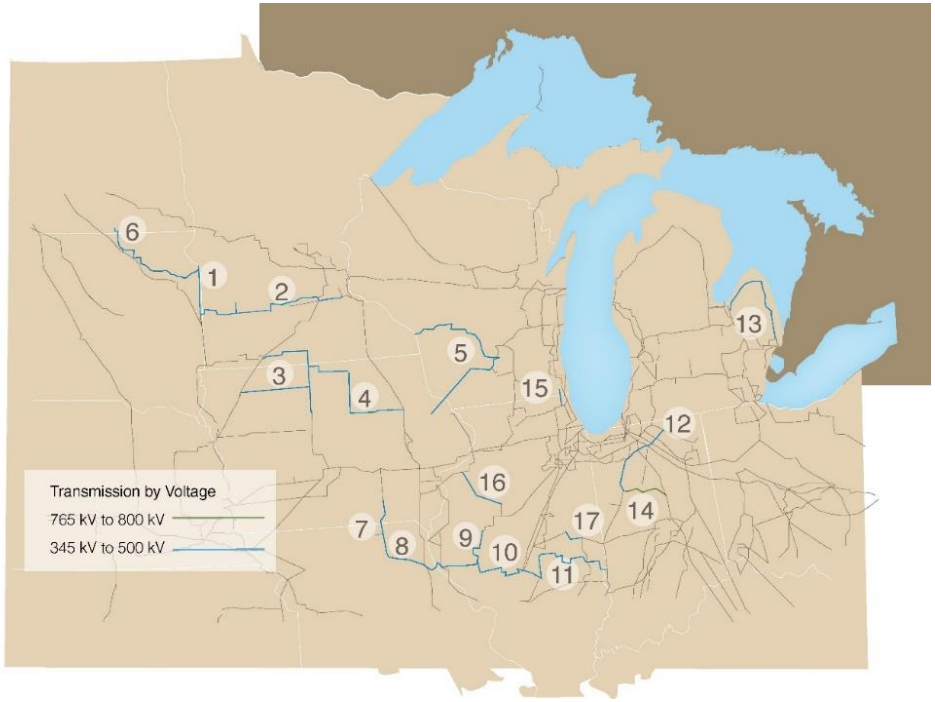


- Texas is home to one-quarter of America's installed wind capacity, hosting over 22GW out of 90GW installed nation-wide as of December 2017.
- The majority was enabled by a $7bn investment in the Competitive Renewable Energy Zone (CREZ) transmission lines, which connect West Zone and Panhandle wind to load centers in the East. The CREZ lines can accommodate roughly 12.7GW of West Zone and 5.8GW of Panhandle wind before significant curtailment (and congestion pricing) comes back into play. Most of this is already filled up, with only 2-3GW of space left on CREZ's lines and a plethora of wind projects proposed in the region.

Source: Bloomberg New Energy Finance, ERCOT, EIA. Note: The Texas map displays all commissioned wind in Texas, including those outside of ERCOT.

Deployment: Transmission build-out in MISO and Mountain West

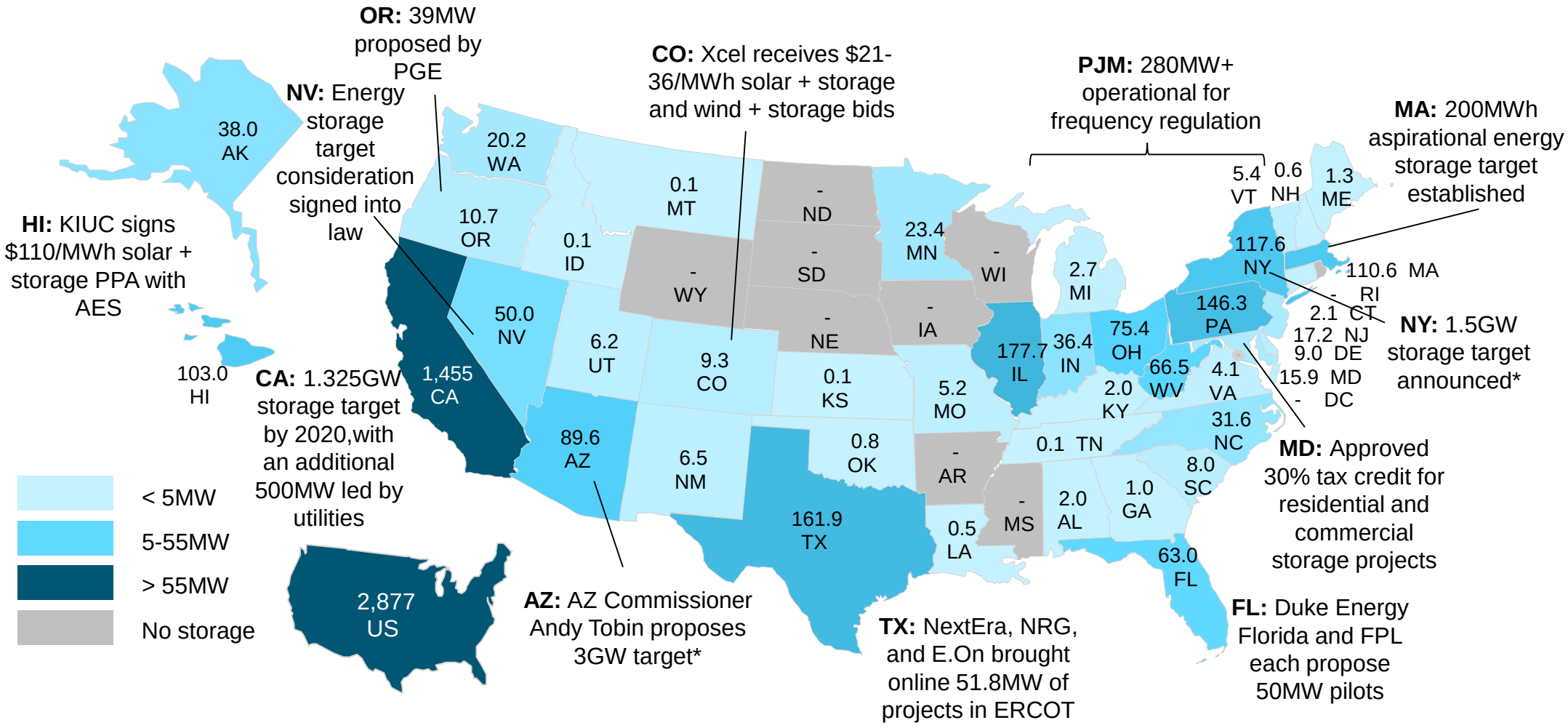
MISO Multi Value Project transmission portfolio



Source: Midwest ISO; MISO MTER14 MVP Triennial Review, September 2014.
Notes: Projects are as follows: (1) Big Stone–Brookings, (2) Brookings, SD–SE Twin Cities, (3) Lakefield Jct.–Winnebago–Winco–Burt Area & Sheldon–Burt Area–Webster, (4) Winco–Lime Creek–Emery–Black Hawk– Hazleton, (5) LaCrosse–N. Madison–Cardinal & Dubuque Co– Spring Green–Cardinal, (6) Ellendale–Big Stone, (7) Adair–Ottumwa, (8) Adair–Palmyra Tap, (9) Palmyra Tap–Quincy–Meredosia–Ipava & Meredosia–Pawnee, (10) Pawnee–Pana, (11) Pana–Mt. Zion–Kansas–Sugar Creek, (12) Reynolds–Burr Oak–Hiple, (13) Michigan Thumb Loop Expansion, (14) Reynolds–Greentown, (15) Pleasant Prairie–Zion Energy Center, (16) Fargo-Galesburg–Oak Grove, (17) Sidney–Rising.

- The American Wind Energy Association (AWEA) estimates that transmission proposals across the U.S. could potentially enable 52GW of wind capacity between 2017 and 2024. This does not include transmission associated with AEP's Wind Catcher Energy Connection.
- AWEA's estimate includes the 14GW-enabling[1] Multi Value Project (MVP) transmission portfolio currently underway by the Midwest Independent System Operator (MISO). There are 17 projects within MVP: Five of these are already complete, 11 are expected to come online by 2019, and one by 2023. This expanded MISO transmission capacity is expected to fill up quickly—thirty gigawatts of wind and 15GW of solar are already in the MISO interconnection queue as of December 2017.
- Finally, five high-voltage DC transmission projects by Clean Line Energy Partners represent 16GW of potential wind capacity.
  - These projects have seen a myriad of challenges, including the Missouri Public Service Commission's denial of the Grain Belt Express application.
  - NextEra Energy Resources acquired Clean Line's Plains & Eastern project assets in Oklahoma, after the project struggled to sign on the Tennessee Valley Authority as an offtaker.
- Many of the proposed transmission projects have yet to begin construction and much of this will not be built. Generally, transmission build *within* a specific state or region receives full approval faster than those that cross multiple jurisdictions. Furthermore, utility-owned transmission projects have typically seen more success than private lines. The Transwest Express line, which expects to commission by 2021, has been under development since 2005 – meaning if the asset comes online, it will have taken 16 years to develop.

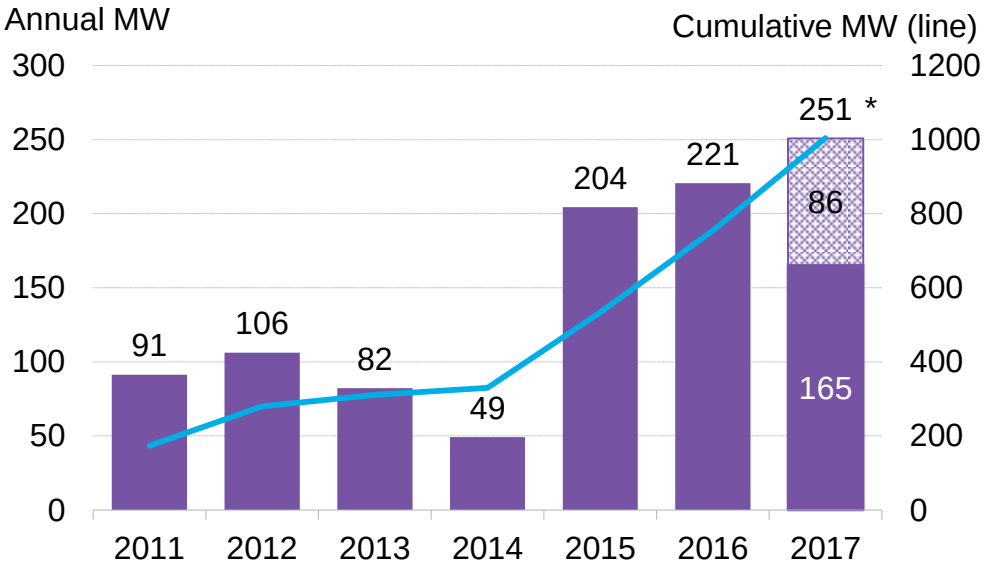
Deployment: U.S. announced and commissioned energy storage projects



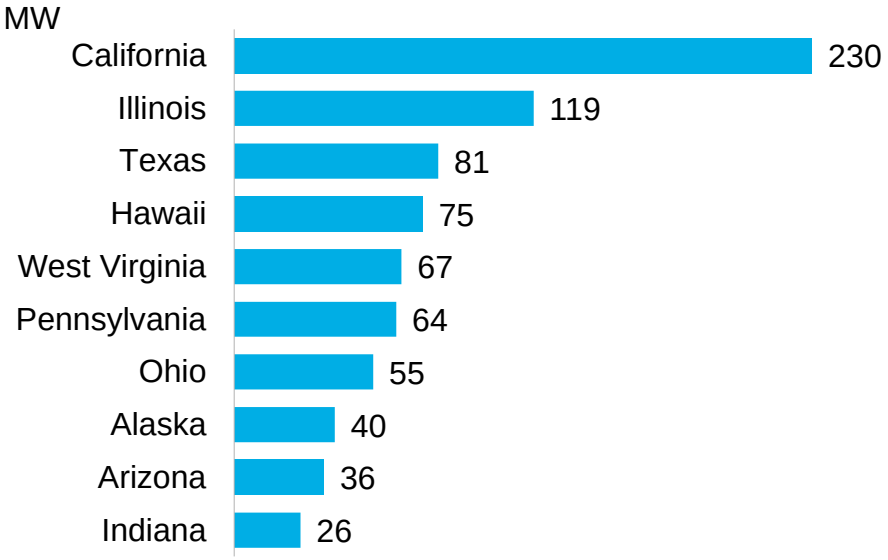
*Source: Bloomberg New Energy Finance Note: Includes projects that are larger than 500kW/500kWh, have announced a specific location, and has been confirmed by the relevant company through public data. *These targets were proposed in January 2018*

Deployment: U.S. non-hydropower commissioned energy storage capacity

Commissioned capacity



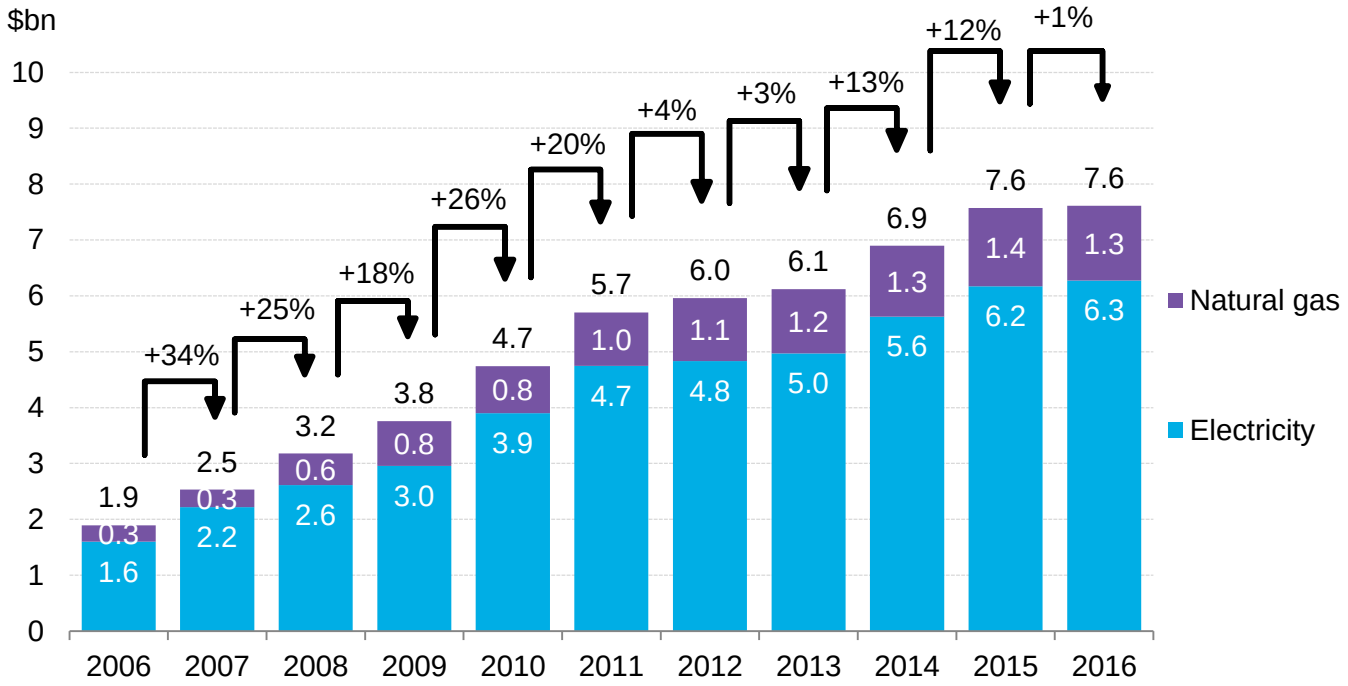
Installations by state (top 10 states)



- Annual energy storage installations have increased since 2014, and is expected to do so again in 2017. Build ramped up in 2015 from projects seeking to participate in the PJM frequency regulation market – those represent most of the capacity in Illinois, West Virginia, Ohio and Pennsylvania.
- While PJM states are still, in aggregate, the biggest energy storage market in terms of commissioned capacity in the U.S., California is the largest single state market. The majority of the commissioned capacity there was built between late 2016 and early 2017 as an emergency response to the gas supply shortages expected from the Aliso Canyon gas storage facility leak-mitigation efforts.
- Beyond California and PJM, many smaller projects have commissioned in other states such as Hawaii, Texas, Indiana and New York.
- Falling lithium-ion battery pack prices have helped to lower costs for new stationary storage applications (see here).

*Source: Bloomberg New Energy Finance Notes: *2017 includes expected but unconfirmed capacity as of January 31, 2018. Unconfirmed capacity is marked in white. Does not include pumped hydropower, underground compressed air energy storage, or flooded lead-acid batteries. Minimum project size for inclusion in this analysis is 500kW or 500kWh. Cumulative capacity subtracts capacity that was decommissioned. Installations by state includes only confirmed capacity.*

Financing: U.S. utility energy efficiency spending

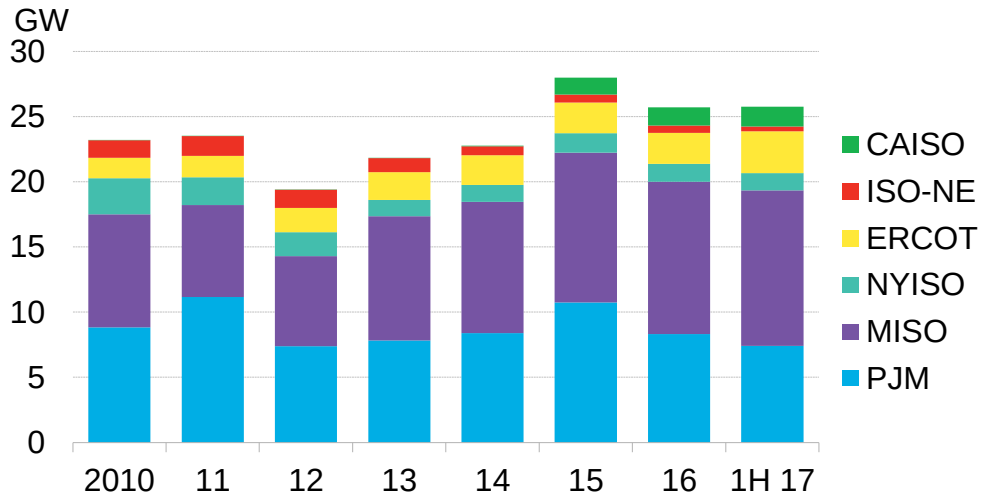


- In 2016, growth in utility spending on energy efficiency level off at $7.6bn, only 1% higher than the previous year. This reflects the slowdown in new states introducing EERS policies and the maturing of many states schemes.
- While investment growth eased at the national level, the picture was more dynamic at the state level. Utilities in Washington increased spending by $34m (+11%), and there were also notable increases in Indiana (+$34m, +33%), North Carolina (+$31m, +21%) and Kentucky (+$30m, +38%).
- However, these gains were offset by falling investment in California (-$57m, -3%) and Maryland (-$90m, -44%). The decrease in Maryland stems in part from a general decline in investment by the state's utilities. The drop-off in California is relatively minor when compared against the increase from $1.57bn to $1.71bn between 2014 and 2015.

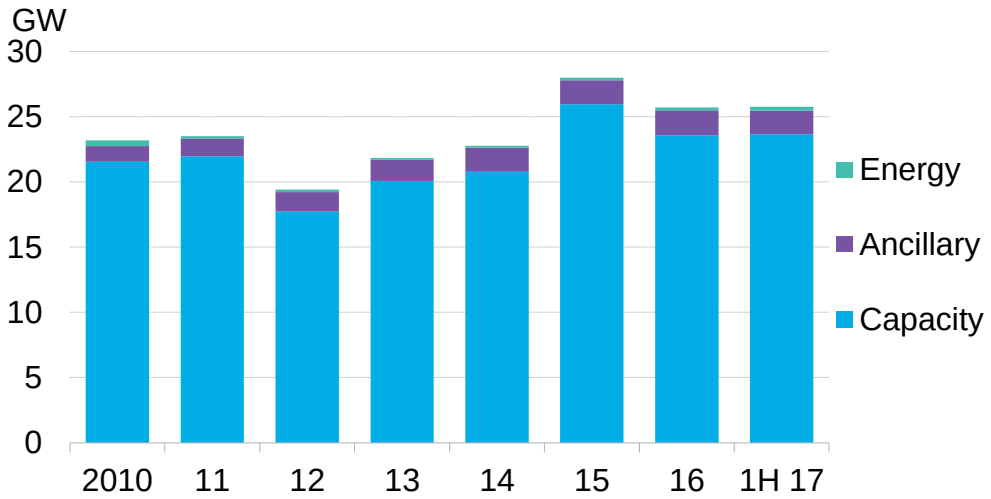
Source: CEE, ACEEE, Bloomberg New Energy Finance. Note that data for 2010-14 was sourced from CEE, and for 2006-2009 and 2015-16 from the ACEEE.

Deployment: U.S. wholesale demand-response capacity

By region



By application

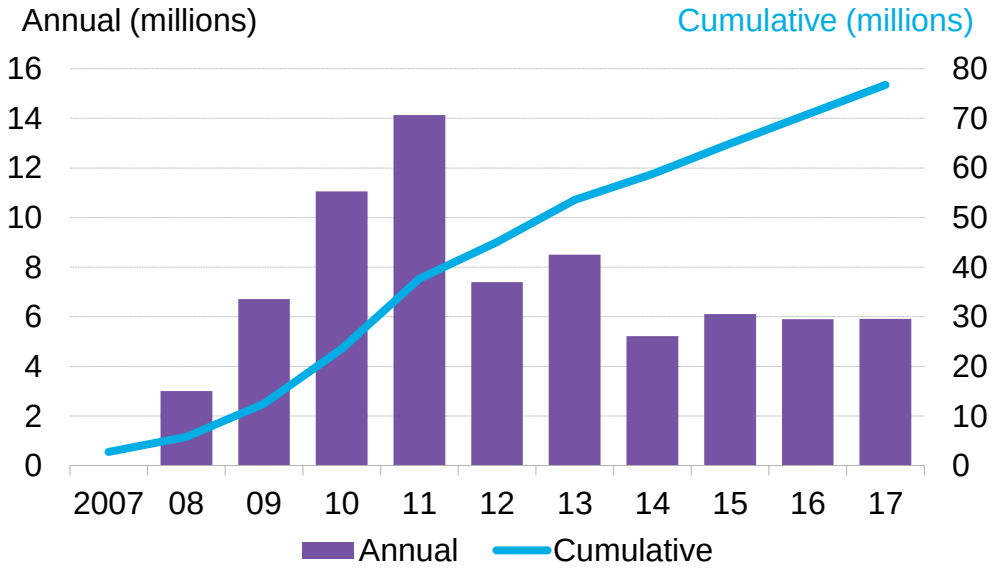


- U.S. wholesale demand-response (DR) capacity remained flat through the first half of 2017, growing a measly 61MW. Despite growth in some markets – notably ERCOT which jumped to 3.2GW from 2.4GW in 2016 – it only just offsets the continued erosion of DR capacity in the Northeast. PJM volumes declined for the second year in a row, while ISO-NE capacity dropped for the sixth straight year. A variety of changes to the capacity markets in both ISOs have challenged demand response and will put downward pressure on volumes and revenue in the years ahead.
- The vast majority of wholesale demand response is concentrated in capacity markets and reliability mechanisms. Even in ERCOT which has no formal capacity market, almost 1.9GW of DR has been contracted through its capacity-style *Emergency Response Service.* Ancillary service participation, which grew 9% annually on average over 2010-2015, has remained flat since, in the 1.8-1.9GW range. Despite the furor surrounding FERC 745, demand response activity within the energy markets remains negligible.
- Our methodology for tracking demand-response capacity has changed since last year. Previously we used data reported to FERC and the results of capacity auctions. This year's analysis is built bottom-up by assessing the amount of demand response active within each market in each ISO/RTO. The most notable change is in PJM, where for some years the GW value is as much as a third lower than previously.

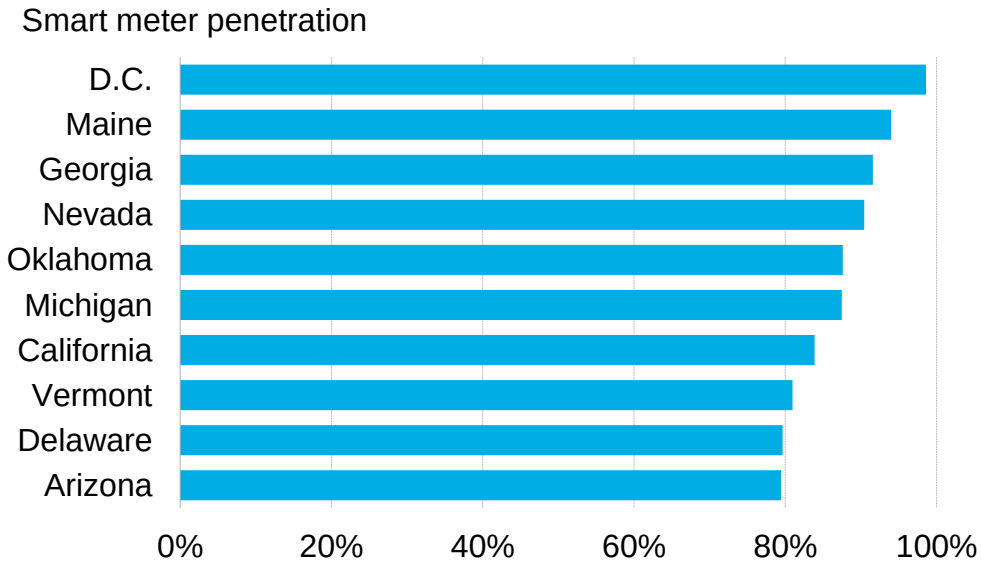
Source: Bloomberg New Energy Finance. Note: Demand-response was only formally integrated with the CAISO market in 2015.

Deployment: U.S. smart electricity meter deployments

U.S. smart meter deployments



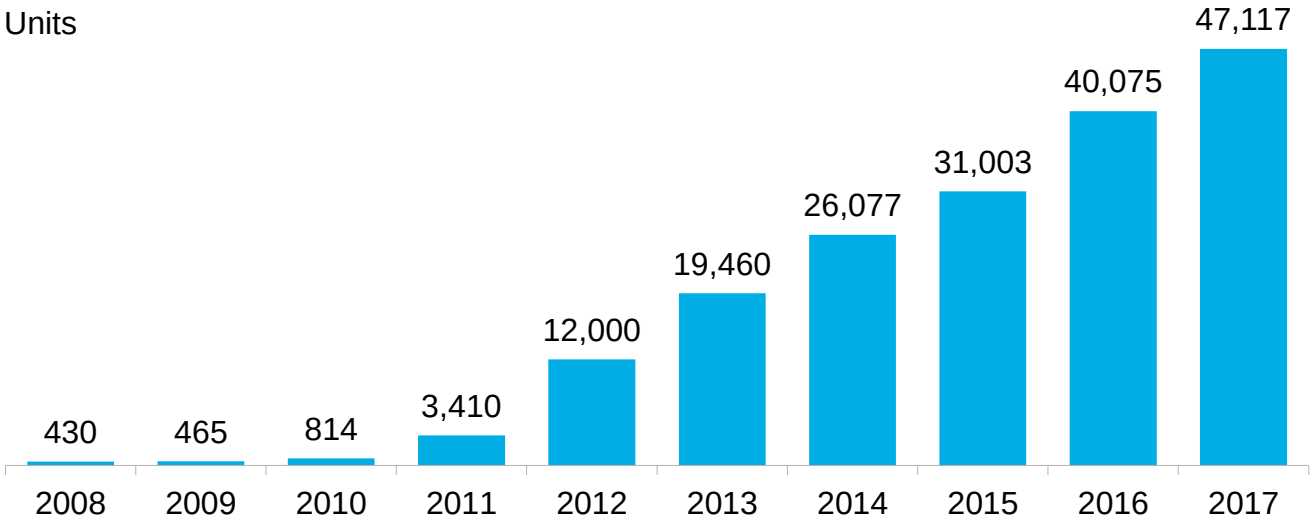
Top 10 states by penetration



- Smart meter installations hit a peak in 2010 and 2011, supported by stimulus funding awarded in 2009. Many of the largest U.S. utilities took advantage of the Smart Grid Investment Grant to roll out smart meters across their territories. As grant funding dried up, deployments slowed, hitting a trough in 2014. Smart metering activity has since increased to a fairly constant six million meters per year.
- Today almost 51% of U.S. electricity customers have a smart meter, but there is enormous regional variation. The top 10 states all have penetration of greater than 79%. In contrast only one in five or fewer customers have smart meters in the bottom 10 states. Over 2016-17, Illinois and Michigan were the most active smart metering markets, deploying 2.4 and 1.1 million meters, respectively.
- The greatest cost saving for utilities from smart metering is replacing the need for manual meter reads. But a renewed focus on grid modernization and growing interest in dynamic retail tariffs is leading state regulators and utilities that have shied away from the technology to reassess the benefits of deployment. Hold-out states, such as New York and Rhode Island (where smart meters currently number in the hundreds), have both committed to extensive smart meter rollouts over the next five to ten years.

Source: Bloomberg New Energy Finance, EIA. Note: there is a 10-month lag in official smart meter statistics, as a result 2017 figures include BNEF estimates.

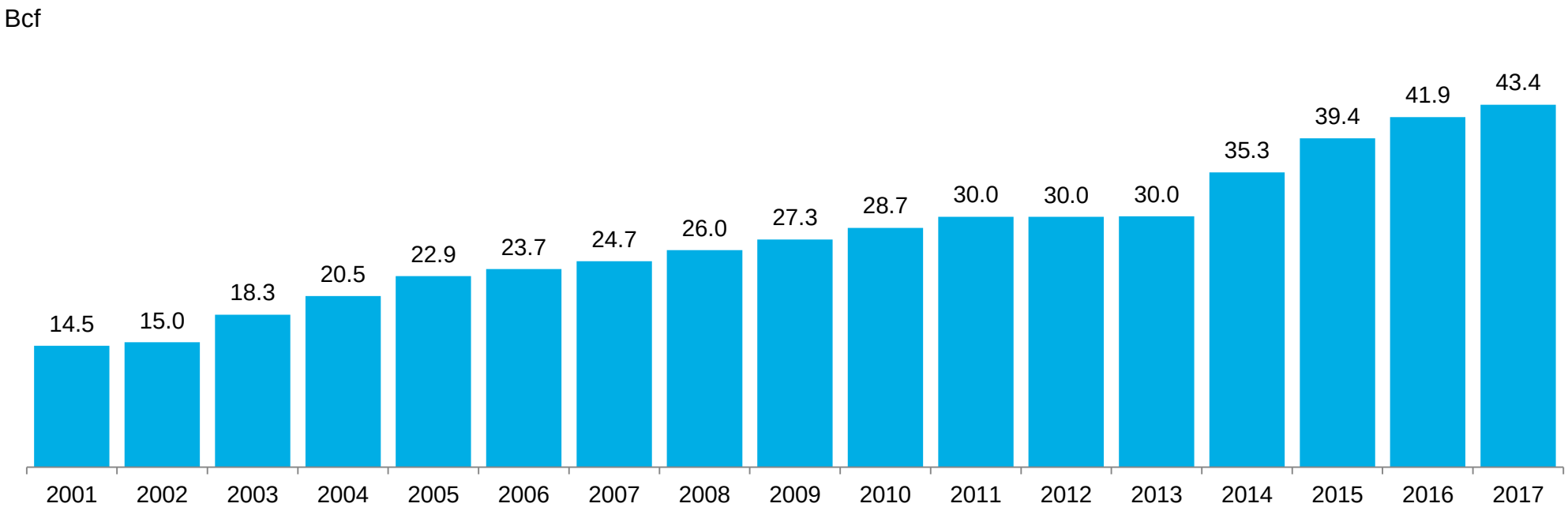
Deployment: U.S. public electric vehicle charging outlets



- There are currently 47,117 public and workplace charging outlets in the U.S., including 6,270 fast charging outlets. The number of charging sites in the country grew 18% in 2017 compared to 2016.
- Over 81% of public charging outlets in the U.S. are Level 2 J1772 (delivering around 7.2kW). This is largely a reflection of the EV fleet in the country, where 45% of electric vehicles come equipped with J1772 outlets. (The majority of EV charging takes place at home, usually with Level 1 or Level 2 J1772 outlets.) Another 13% of the charging outlets is split between different rapid charging standards – CHAdeMO (30%), CCS (23%) and Tesla Supercharger (45%). Some 6% of public charging outlets are Level 1.
- The Volkswagen Group, under the terms of a legal settlement with the State of California and the U.S. Environmental Protection Agency (EPA), created a subsidiary called Electrify America that will spend a total of $0.8 billion over ten years to deploy charging infrastructure within California and $1.2 billion over a decade outside California.

Source: Alternative Fuels Data Center, Bloomberg New Energy Finance Notes: Does not include residential electric charging infrastructure.

Deployment: U.S. natural gas demand from natural gas vehicles



- Natural gas use in vehicles has grown steadily since 2013. In 2017, the amount of natural gas used for this purpose rose 4% year-on-year to 43.4Bcf. This represents a 44.5% increase over 2013 levels, and a 5.9% compounded annual growth rate over the last decade (since 2008). The pick-up in 2014 coincided with the start of a period of low natural gas prices across the U.S.
- Compressed natural gas (CNG) remains more widely used than liquefied natural gas (LNG), and this is reflected in the amount of fueling infrastructure available for each technology. As of January 18, 2018, there were 1,676 CNG stations across the U.S., compared to 137 LNG stations (including public and private stations).
- The number of CNG and LNG stations shrank slightly from 2016, when the CNG station count had hit 1,725 and the number of LNG stations hit 140.

Source: EIA, Alternative Fuels Data Center Notes: Values for natural gas demand in 2017 are projected, accounting for seasonality, based on latest monthly values from EIA (data available through October 2017). Data excludes gas consumed in the operation of pipelines.