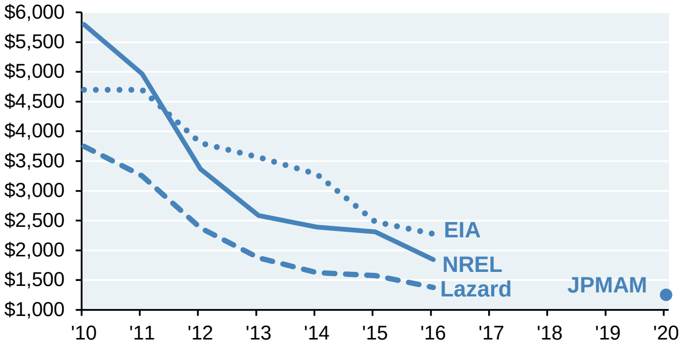
## [#1] Falling photovoltaic solar and energy storage costs: what's next for the electricity grid?

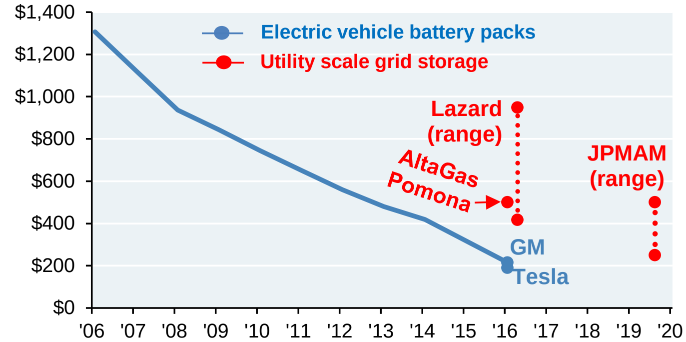
Solar and energy storage costs continue to fall. These declines reflect innovation and benefits from mass production, and are welcome signs on the road to greater adoption of renewable energy for electricity.

**Utility scale solar PV capital cost estimates**
US$/kW-AC, assuming 1.3 inverter DC-AC loading ratio




Source: NREL, EIA, Lazard, JPMAM. April 2017.

**Lithium ion energy storage costs: EV battery packs vs utility scale grid storage,** capital cost per kWh



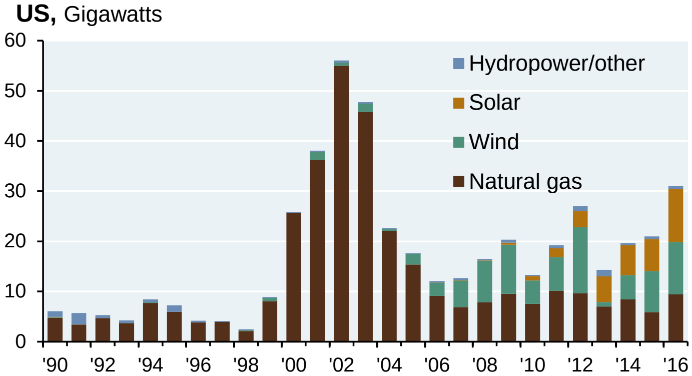

Source: Lazard, Nykvist, et. al., Green Car Reports, Utility Dive. April 2017.

Before we dig deeper into this, let's distinguish between two kinds of lithium ion battery storage:

- *Electric vehicle battery packs*. EV battery costs are sometimes cited solely based on the cost of their component lithium ion *cells*, but the more useful number is the one which includes the additional materials required to create an EV battery *pack* [blue line and points in chart]
- *Utility-scale storage for replacing peaker plants*. When using batteries to store energy for use on electricity grids[4], there are additional costs, including DC to AC inverters, power conditioning hardware, software, meters and land/construction costs. The red dots in the chart show a range of cost estimates from Lazard, an actual facility completed in Pomona in 2016 and our forecasts

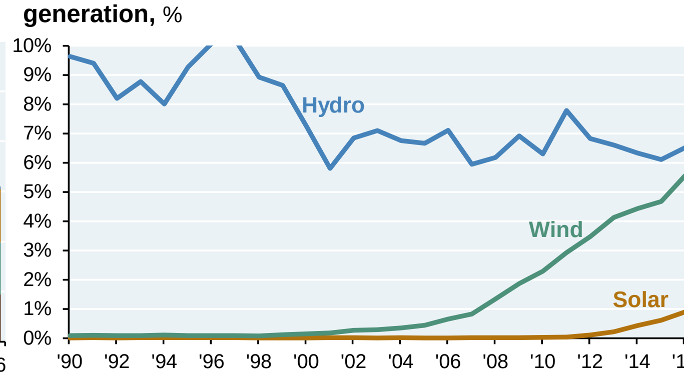
**What does this all mean for electricity grids?** After a decade of investment in wind and solar capacity, their contribution to US electricity generation is rising. Total US renewable generation is ~15%, with almost half from hydroelectric. The pace of renewable energy penetration reflects wind and solar *marginal* costs, and the *system* costs of integrating them, which entails both backup thermal power capacity and transmission infrastructure from what are often remote places.

**Annual electricity generating capacity additions in the US,** Gigawatts




Source: U.S. Energy Information Administration. 2015. 2016 are estimates.

**Wind, solar and hydroelectric shares of US electricity generation,** %

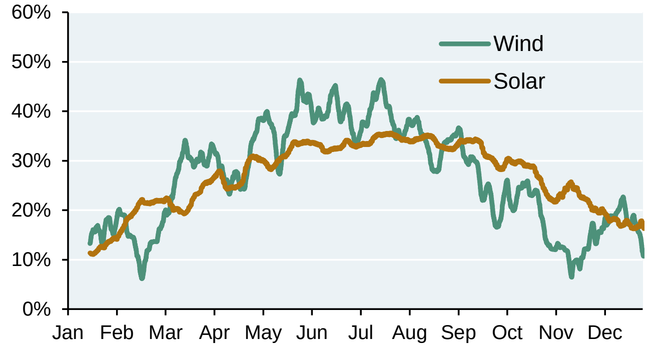



Source: Energy Information Administration. December 2016.

[4] There will be a lot of lessons learned about the real-life implications of using chemical battery storage for grid purposes. To be clear, this isn't really happening yet. As of 2015, **97% of global energy storage was still based on hydroelectric pumped storage**; batteries like those analyzed in this section represented less than 1%.

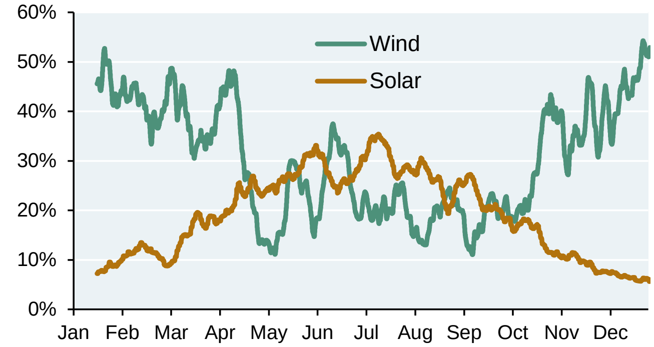
**To understand wind and solar intermittency, consider the charts below**. They show capacity factors for wind and solar power in California and New York throughout the year (using 2016 as an example). Capacity factors measure actual electricity generation for a given facility compared to its potential generation, assuming it was generating electricity on a 24/7/365 basis.

**California wind and solar capacity factors by month**
%




Source: CAISO, EIA, JPMAM. 2017.

**New York wind and solar capacity factors by month**
%




Source: NYISO, EIA, JPMAM. 2017.

Important inferences from the charts:

- In California, wind and solar efficiency both peak in the summer months. On some summer days, California could meet all of its load through wind and solar power if enough of it were built. However, in winter months, large amounts of backup thermal generation would be needed, since California's electricity demand is roughly constant throughout the year.
- In New York, while solar productivity is lower than in California, it is less correlated to wind, which could smooth overall renewable generation
- This is usually when someone will say "**What about energy storage!** We can store any excess renewable energy and then use it later. We would reduce thermal generation and corresponding costs and emissions." **Yes you can**, as long as you recognize the following:
  - Battery storage is primarily designed to store power for a few days or weeks at most, and is not meant to store power for months at a time, even if adequate energy surpluses were available
  - Battery storage has limitations in terms of how much energy can be stored on an instantaneous basis and on a cumulative basis, and also entails efficiency losses
  - As a result, a system with energy storage can smooth out short-term periods of low wind/solar energy and use less backup thermal power. But it will still need backup thermal power to handle residual demand during periods of fallow renewable generation, after stored energy has run out
  - Putting the pieces together, **the net cost of energy storage** reflects (a) the increase in cost from building the storage, less (b) the fuel[5], fixed and variable costs of thermal generation that storage replaces. Whether this outcome is a net cost or a net savings depends on the specific characteristics of the grid in question, and its renewable energy profile

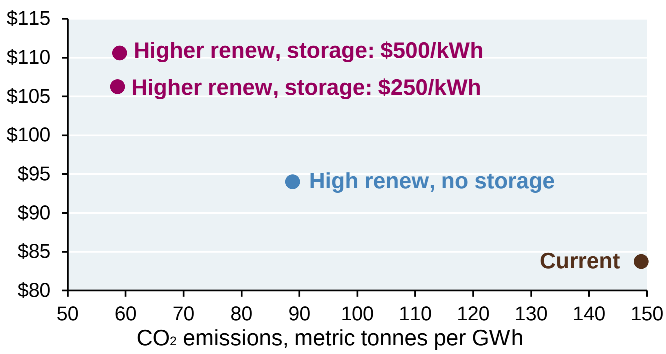
**This is where it gets fun and interesting, if you enjoy electricity grid modeling as I do.**

[5] Fuel savings from energy storage can be substantial; **40%-60%** of the annual levelized cost of natural gas powered electricity is the fuel itself, depending on capacity factor and natural gas price assumptions

**How do we model this?** We start with hourly generation and load data for California and New York from 2016. To meet the hourly load, baseload power from nuclear is used first; then renewables of all kinds; then natural gas to meet residual demand. Using current information and applying learning curve estimates for the near future (i.e., 2020), we examined the cost and $CO_2$ emissions of the current grid, a grid with higher renewable penetration, and a high-renewable grid with storage. For our cost and capacity factor assumptions, please see the Supplementary Materials at the end of this section.

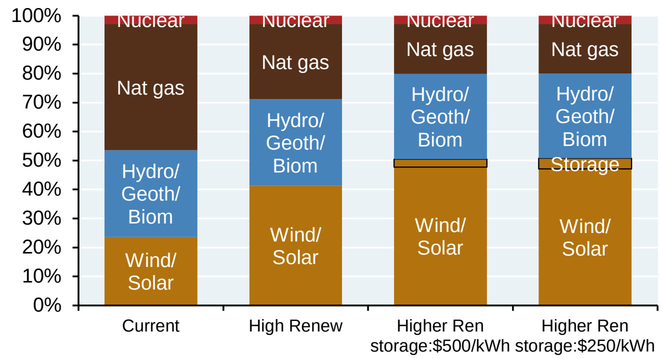
**California** already meets 50% of electricity demand via renewables[6]. As per our analysis, a California grid which met ~70% of demand via renewables would increase costs by 10%-15% in exchange for a 40% decline in emissions. This trade-off has improved substantially in the last few years. **Could energy storage help reduce emissions further?** To get to a 60% emissions decline, a larger build-out of solar could be accompanied by energy storage. However, net system costs rise further since foregone gas variable costs are less than the cost of building and maintaining the storage and the additional solar. The slope of the cost increase would look a bit better if storage costs fell to $250/kWh.

**California electricity cost-emission tradeoffs,**
US$ system cost per MWh




Source: CAISO, EIA, JPMAM. 2017.

**California electricity generation scenarios**
Share of electricity generation




Source: CAISO, JPMAM. 2017. Includes allocation of electricity imports.

Let's be clear about the limits of these theoretical calculations, since there **are some unknowns:**

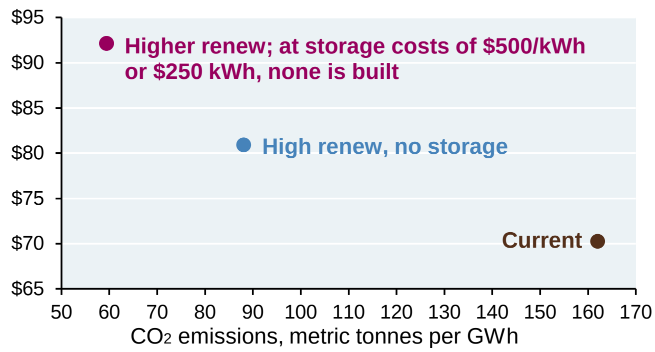
- our estimates include the cost of connecting facilities *to* the grid, but *do not* include costs of building high voltage transmission lines from what are often remote locations. Our research on dedicated transmissions lines suggests that their costs could add **another $15-$20 per MWh** to wind and solar costs, over and above the $2-$4 per MWh assumed by the EIA for grid interconnection
- we optimized the buildout of solar and wind based on 2016 solar irradiance and windiness patterns; actual wind and solar patterns change from year to year, rendering our assumptions less optimal
- the "best" wind and solar locations are often built out first, so one cannot assume an inexhaustible supply of high capacity factor locations as wind and solar capacity expands
- consequences of high-renewable grids may not yet be fully understood (more frequent up/down ramping of natural gas plants; true field-level operating and maintenance costs of wind/solar/storage; wind/solar capacity factor degradation rates due to the passage of time and due to site density)

[6] Many US states **import** energy from neighboring states. We allocate energy imports to respective generation categories using available information. For example, California imports hydropower and wind from the Northwest and solar from the Southwest, which boosts its "look-through" renewable generation percentage to ~50%.

On **nuclear**, as per state announcements, we assume that California's Diablo Canyon and New York's Indian Point plants are closed in the analysis. However, we do not include estimates of decommissioning costs or stranded asset costs, or ratepayer implications of adding wind and solar before the useful life of nuclear plants have expired.

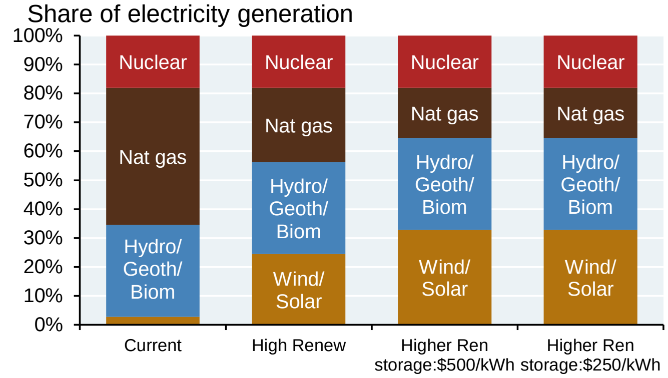
***New York***. This is more of a theoretical exercise, since in NY, wind/solar comprise only 3% of electricity generation. But in principle, NY could also reduce $CO_2$ emissions to 90 MT per GWh in exchange for a ~15% increase in system costs. One difference vs California is that NY's build-out would start from a much lower base. The other difference is that storage is less optimal given lower NY solar capacity factors. Instead, a more cost-effective approach to reaching the deeper 60% emissions reduction target would be to build more wind/solar and discard ("curtail") the unused amount, and not build any storage.

**New York electricity cost-emission tradeoffs,**
US$ system cost per MWh




Source: NYISO, EIA, JPMAM. 2017.

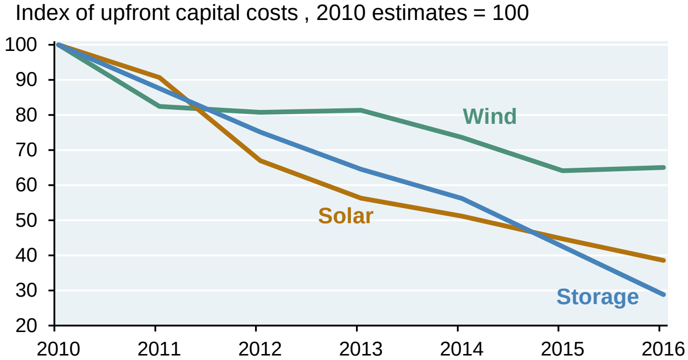
**New York electricity generation scenarios**
Share of electricity generation




Source: NYISO, JPMAM. 2017. Includes allocation of electricity imports.

***Conclusions.*** Scale and innovation are creating cost-benefit tradeoffs for decarbonizing the grid that are more favorable than they were just a few years ago, even when including backup thermal power costs. However, this is likely to be a gradual process rather than an immediate one. Bottlenecks of the past were primarily related to the high capital cost of wind, solar and storage equipment. The next phase of the renewable electricity journey involves bottlenecks of the future: public policy and the construction/cost of transmission are two of the larger ones[7]. As is usually the case with renewables, there's a lot of hyperbole out there. The likely trajectory: renewables meet around one third of US electricity demand in 2040, with fossil fuels still providing almost twice that amount.

**Bottlenecks of the past: upfront capital costs**
Index of upfront capital costs , 2010 estimates = 100




Source: EIA, NREL, Lazard, UBS, Nykvist, et. al. December 2016.
Storage proxied by electric vehicle battery packs.

**Bottlenecks of the future:**

- Construction cost and eminent domain issues of high voltage direct current transmission lines often required due to remote wind and solar locations
- True operating and maintenance costs and useful lives of wind, solar and storage observed in the field after prolonged use
- Wind and solar capacity factor degradation from passage of time and suboptimal site placement and/or site density, as installations grow from megawatts to gigawatts, and require hundreds of thousands of acres of land
- Availability and pricing of rare earth elements, lithium and other commodity supply chains

[7] The Plains & Eastern Clean Line (Texas panhandle to Memphis) is the first long-distance US HVDC transmission line built in more than 20 years, at annual cost of $15-$20 per MWh. If finished on time, it will have taken **11 years to complete**, and required the Dep't of Energy to invoke Section 1222 of the Energy Policy Act on eminent domain.

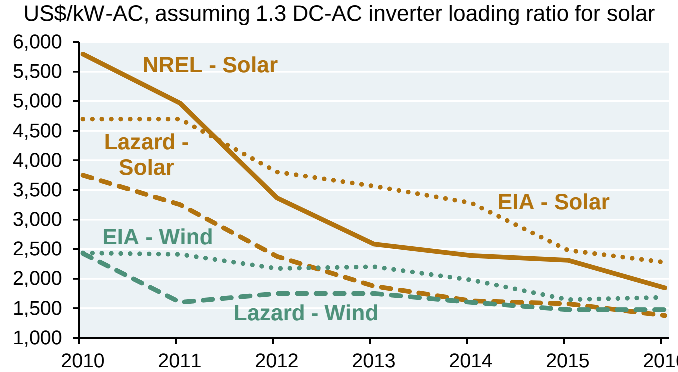
Electricity Grid supplementary materials: costs and capacity factors

The following table shows our cost assumptions for 2020 electricity grid configurations:

| | Capital $/kW | Capital $/kWh | Fixed O&M $/kW-y | Var O&M $/MWh | Fuel $/MWh | Fuel $/MMBtu | Heat rt Btu/kWh | Useful life (yrs) | GridConn. $/MWh |
|---|---|---|---|---|---|---|---|---|---|
| Wind | $1,500 | | $40.0 | | | | | 20 | $2.90 |
| Solar PV | $1,250 | | $16.0 | | | | | 20 | $3.80 |
| Solar thermal | $4,182 | | $70.3 | | | | | 20 | $6.10 |
| Hydro | $2,442 | | $14.9 | $2.7 | | | | 20 | $1.50 |
| Biomass | $3,790 | | $110.3 | $10.0 | $29.0 | $2.00 | 14,500 | 20 | $1.20 |
| Geothermal | $2,715 | | $118.0 | | | | | 20 | $1.50 |
| Nuclear | $5,880 | | $125.0 | $2.3 | $8.9 | $0.85 | 10,459 | 40 | $1.00 |
| Natural gas combust turbine | $672 | | $6.8 | $10.6 | $39.2 | $4.00 | 9,800 | 30 | $3.00 |
| Natural gas combined cycle | $969 | | $8.0 | $3.5 | $26.4 | $4.00 | 6,600 | 30 | $1.10 |
| Battery storage | | $250-$500 | $5.0 | | | | | 15 | $0.00 |

Sources: Energy Information Administration, Lazard Levelized Cost Analyses, National Renewable Energy Laboratory, JPMAM. 2017. Discount rate for converting upfront costs into annual costs: 10%. Lithium ion battery storage round trip efficiency: 85%, 4 hour run time. All costs exclude subsidies, tax credits and other incentives.

**Utility-scale solar PV and wind capital cost estimates**
US$/kW-AC, assuming 1.3 DC-AC inverter loading ratio for solar




Source: NREL, EIA, Lazard, JPMAM. April 2017.

Note that our **wind** capital cost projections do not assume substantial learning curve benefits from here. Wind is a more mature technology whose costs have been more stable for the last few years. Even on **solar PV**, the learning curve won't yield benefits forever. The IEA projects that by 2020, solar PV upfront capital costs per kW will begin to flatten out at $900 to $1,000.

**What are "levelized costs"?** Once you assume capital and O&M costs, useful lives, capacity factors and a discount rate, you can derive an annual "levelized" cost for each kWh generated by a given electricity source. Levelized costs are widely reported by the EIA, NREL and Lazard, and are *partially* useful in understanding the cost of electricity. **However, for wind and solar power, levelized costs do not include the cost of building, maintaining and using backup thermal power, which renders the concept less useful.** That's why we compute overall system cost per MWh, since it factors in backup thermal power needs. In most high-renewable scenarios we modeled, there was not much of a decline in required thermal capacity due to prolonged periods of low wind and solar generation at different points of the year.

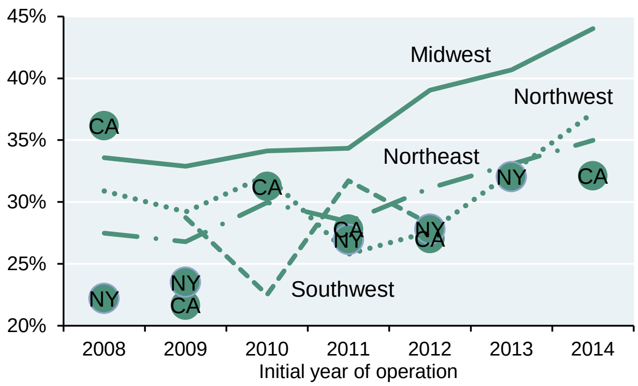
**What if natural gas prices rise?** We also ran our models assuming natural gas costs of $8 per MMBtu (vs the $4 baseline case). In California, at $8 gas, the high renewable case with storage at $500 per kWh resulted in a cost increase of 21% vs the current grid (instead of 32%) to achieve the same 60% decline in emissions. In other words, high renewable scenarios entail better tradeoffs at higher assumed natural gas prices, but within similar orders of magnitude.

**What about rising capacity factors?** Capacity factors can be a moving target. Midwest wind is a good example: the first chart shows how Midwest wind capacity factors have been rising. In other cases, improvements are slower and constrained by the region's level of windiness or solar irradiance. After triangulating available data, we assumed the following for steady-state capacity factors:

- California: wind capacity factor 32%, solar capacity factor 29%
- New York: wind capacity factors 33%, solar capacity factor 19%

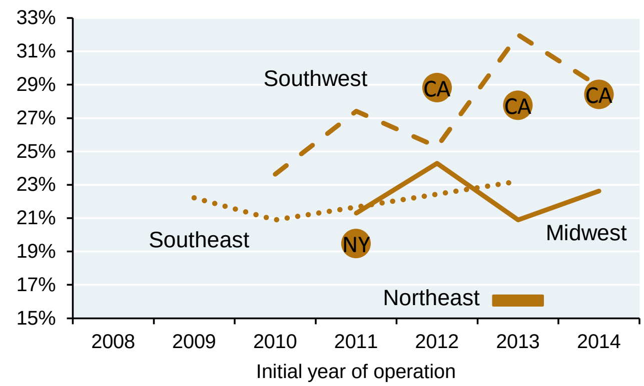
In a normalized analysis, capacity factors should not just reflect *peak* performance of new builds. As NREL has found, **solar capacity factors tend to degrade at a median rate of 0.5% per year[8].**

**Wind capacity factors based on initial year of operation**




Source: EIA, based on form 923/860 data. 2016.

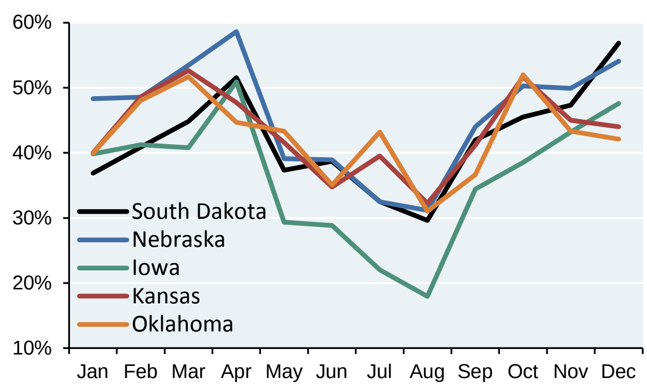
**Solar capacity factors based on initial year of operation**




Source: EIA, based on form 923/860 data. 2016.

## On Midwest Wind

**Wind capacity factors by month for Midwestern states**




Source: EIA, based on form 923/860 data. 2016.

The rising capacity factors of Midwest wind are impressive; ~50% during winter months, and ~35% during summer months. MidAmerican Energy (a Des Moines-based utility serving Iowa and parts of neighboring states) plans to rely 66% on wind by 2020. However, electricity consumption in the 8 Midwestern and Northwestern states with high wind capacity factors (> 36%) and low population density (below 60 people per square mile, leaving plenty of room for wind farm construction) is only 6% of total US electricity consumption. In other words, **wind dynamics in Iowa, Oklahoma, Nebraska, Kansas and the Dakotas are compelling, but to have a larger national impact, these states would have to overbuild and export electricity to places like Chicago, St. Louis, Houston and Dallas.** The required buildout of high voltage (i.e., 765 kW DC) power lines would involve substantial fiscal commitments, and regulatory ones as well. The Plains & Eastern Clean Line (from the Texas panhandle to Memphis, Tennessee) is the first long-distance HVDC transmission line built in more than 20 years in the US, at annual cost of $15-$20 per MWh. If finished on schedule, it will have taken 11 years to complete, after having required the Department of Energy to invoke Section 1222 of the Energy Policy Act regarding eminent domain.

[8] "*Photovoltaic Degradation Rates - An Analytical Review*", NREL, Jordan and Kurtz, 2012.

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