

It is time to replace LCOE

Hi, welcome to this USAEE podcast, titled "it is time to replace LCOE." My name is Gürcan Gülen. I am an energy economist with more than 25 years of international experience and a USAEE Senior Fellow. This is a follow up to my previous podcast titled "are electricity markets 'markets'", and is also based on [Net Social Cost of Electricity](#), a report I published in 2019. I encourage listeners to open the PDF of this talk available from the USAEE web site to see the graphics, to which I refer.

The levelized cost of electricity (LCOE) is the metric commonly used to compare the per-MWh cost of generation technologies for a new plant; but only in the media and high-level policy discussions. Because the LCOE is of dubious value for long-term planning to meet growing electricity demand or even to reduce emissions at lowest system cost. And, LCOE is useless in real-time system operations to balance demand and supply instantaneously while maintaining reliability, which, simply put, is 24x7 availability of electricity to all consumers keeping system voltage and frequency in balance at all times. For both short-term and long-term purposes, the cheapest option often would include the optimal use of the T&D grid and demand-side such as demand response to real time price signals. Although short-term system benefits of such demand response are recognized by energy economists, there are longer term benefits as well, such as inducing investment in energy efficiency, conservation, and perhaps even consumer choices towards "living smaller." But asking consumers to pay for the true cost of electricity (inclusive of externalities and system integration costs), or, for that matter, true cost of almost anything we consume, has never been politically popular. Subsidizing technologies in the name of reducing emissions gets campaign support although an [emissions tax could have achieved the same reduction at a lower cost](#). But, this truism of environmental economics is a topic for another day (see some references at the end of this document).

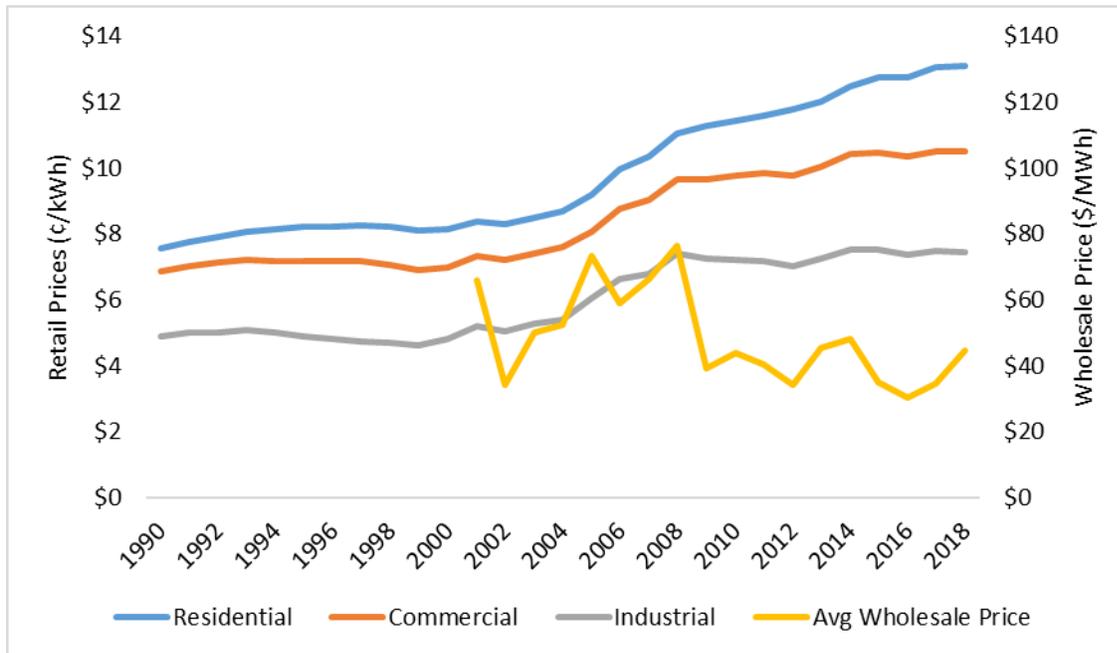
Let me spend some time on why a system operator has to consider all resources inclusive of generation, T&D and demand response to minimize system costs. Despite all the excitement about distributed energy resources (DER) and micro grids, the large-scale T&D grid remains central to reliable electricity service for tens of millions of customers who are not interested in pursuing distributed alternatives. The grid is also necessary for least-cost integration of more renewables because best wind and solar resources are often distant from load centers. Not surprisingly, DER proponents argue that consumers are being burdened by unnecessary transmission costs to bring clean energy from distant locales because DER can provide the same. Karpa of Clean Coalition (Karpa, 2018) criticizes skyrocketing transmission costs in California due to long distance WECC-CAISO lines to bring renewable generation from wind-rich regions. He argues that wholesale distributed generation avoids much of transmission costs and, hence, is a lower-cost alternative for increasing the share of clean energy.

However, DER (prominently rooftop solar) has its own cost implications for customer bills. For example, although owners of rooftop solar are happy to sell back their excess generation to the grid at retail cost, their share of the distribution grid costs needs to be shifted to customers without rooftop solar or undermine utility creditworthiness. The [net metering debacle](#) and transmission v DER debate are topics for another day but I provide some resources in the PDF of this talk and encourage listeners to research the topics. A related issue is the impact of net energy metering (NEM), a policy used by many jurisdictions to promote DER but in particular rooftop solar. MIT (2015) recommended the elimination of NEM, which shifted costs from those customers with rooftop solar who could sell their excess solar back to the grid at the retail price rather than the wholesale price to those without solar. Craxton and Sweeney (2017) confirm the cost shifting and conclude that the costs of California's NEM policy

outweighs the benefits, especially for certain customers. Fitch Ratings (2016) identified residential PV and NEM as potential long-term threats to utilities' creditworthiness. For a detailed discussion, see [Net Social Cost of Electricity](#).

These debates aside, more than \$200 billion invested in the 2010s on the T&D network, partially to facilitate renewables penetration, is one reason why retail costs have been increasing across the country despite historically low wholesale electricity prices (see chart in the pdf).

United States average retail prices (cents/kWh) and wholesale electricity price (\$/MWh).



Lower-48-states retail prices are from EIA Form-861 annual survey data available at <https://www.eia.gov/electricity/data.php#sales>. Data from 2018 are calculated from monthly data through November 2018 for all 50 states to match historical relationship with the annual data. Average wholesale price is the average of daily prices of eight contracts traded at the Intercontinental Exchange (ERCOT North 345KV Peak, Indiana Hub RT Peak, Mid C Peak, Nepoch MH DA LMP Peak, NP15 EZ Gen DA LMP Peak, Palo Verde Peak, PJM WH Real Time Peak, SP15 EZ Gen DA LMP Peak) and reported by the EIA (<https://www.eia.gov/electricity/wholesale/>).

Back to the grid. The bulk electric grid is a web of T&D wires with different voltages connecting generation facilities with consumers. There are hundreds of nodes, or entry and exit points for electrons if you'd like. Electricity demand and supply must match at all times at all nodes of the power grid. System operators dispatch electricity from a fleet of generation units and, to the extent they are available, call upon demand response resources in order to maintain supply–demand balance in real time at least cost while also maintaining reliability. This demanding balancing task of the system operator is an optimization problem with two complementary components known as security constrained unit commitment (SCUC) and economic dispatch (SCED).

The system has many considerations that vary over time. For example, the transmission network can experience congestion if there are unplanned outages in some generation units or transmission lines and/or unexpected spikes in demand in certain locations. Changes in generation portfolio also need attention since different technologies have differing operational characteristics. For example, fast ramping generators are highly desirable to balance real-time demand and supply, because electricity demand fluctuates significantly throughout the day, unpredictably at times. And, increasingly, supply fluctuates a lot due to penetration of intermittent resources such as wind and solar. In fact, short-term

variability of wind and solar (say due to clouds or storms) can be large enough to matter to the system operator.

The fast-ramping, dispatchable thermal resources, along with an extensive grid, is what allows the addition of renewables. Even in best locations, wind and solar are intermittent and variable, needing backup and balancing from dispatchable resources. Their generation does not always match load profiles and reduces their market value. This mismatch between load profile and generation from nondispatchable resources have led Joskow to declare LCOE flawed in a 2011 article. So, problems with LCOE have been known for a long time at least among energy economists.

There is much excitement about battery storage as a substitute for thermal generators to provide the necessary backup to intermittent resources. But battery storage remains marginal in terms of installed capacity and more expensive than alternatives despite impressive declines in unit costs. Technical issues such as duration of batteries and geopolitical challenges associated with the mining and supply chains of minerals used in battery chemistry will only grow with increased deployment.

So, given this background, we can see that the conventional LCOE formula does not capture any of the electric power system complexities. It is simply a present value estimate of building and operating costs of a new plant. Components of the formula are the plant capacity factor (or utilization), fixed and variable O&M costs, efficiency (heat rate) and fuel costs. The values for each component are assumptions based on either technical studies or historical performance. In the attached pdf, you can find the formula. Overnight capital cost and its financing costs (capital recovery factor, CRF), operating and maintenance costs (fixed O&M, FOM, and variable O&M, VOM), fuel costs (the product of the fuel price and the efficiency of a plant in converting energy content of the fuel into electricity plant, known as heat rate, HR), and annual expected generation (the product of 8,760 hours in a year and the ratio of the net electricity generated in a year to the energy that could have been generated at continuous full-power operation during the same period, known as capacity factor, CF, of a technology).

$$LCOE = \frac{CRF * capital + FOM}{8760 \times CF} + VOM + HR \times fuel\ price$$

This representation of LCOE is an incomplete indicator of competitiveness of different generation technologies because it ignores many factors. And it cannot be applied universally.

There are significant regional differences for each component of the LCOE formula. Probably the largest regional variability emanates from CF. Complicating matters further, some studies use historical CF averages for thermal plants but technical CF maximums for wind and solar. In reality, no technology performs regularly at their design capability due to many reasons. For example, competition, fuel price and subsidized resources often lower the utilization of gas plants but retirement of coal plants increase gas plant utilization. Wind and solar utilization estimates are based on models of wind and solar availability in any location and can vary significantly across models and in operation. For example, utility-scale solar CF estimates range from 21% to 34% in various studies and onshore wind CF estimates from 33% to 55%. In the pdf, you can find a table comparing different assumptions used by 4 studies and their references. For comparison, there is no technical reason why a CCGT plant cannot be run at 80% CF. Nuclear plants in the US have been averaging 90%.

Table: Capacity factor assumptions, technical estimates, and historical data

[Lazard (2018a) range for solar is a mix of crystalline (minimum) and thin film (maximum) photovoltaic (PV). The values from Miller and Keith (2018) represent mean and 90-percentile values corresponding to their power density estimates. Energy Information Administration (EIA) Electric Power Monthly (EPM)]

	EIA (2018c)	Lazard (2018a)	Miller & Keith (2018)	EIA EPM
Onshore wind	43%	33%–55%	32.9%–43%	32.2%–34.6%
Utility-scale solar PV	33%	21%–34%	22.1%–27.5%	25.1%–25.9%

Natural gas price can also vary significantly across regions and over time. It is difficult for LCOE calculations to forecast accurately but current regional differences (basis differentials) and forward curves have to provide the starting point. Otherwise, a generic gas plant LCOE will be off by a wide margin in many regions.

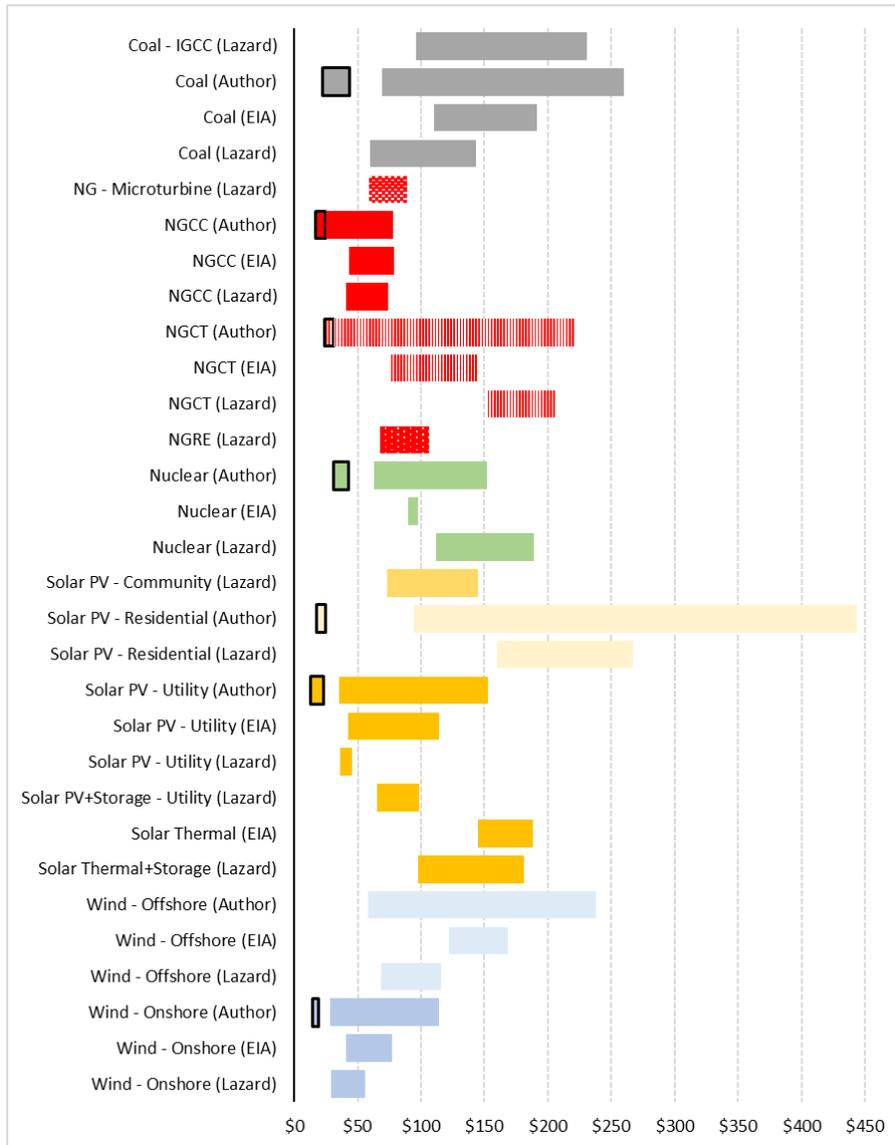
Weighted average cost of capital (WACC) assumptions can vary significantly across studies and highlight the importance of tax credits and other incentives provided to wind and solar as they allow for more attractive financing terms. If incentives are eliminated, WACC and LCOE will increase. The higher the WACC, the greater the LCOE increase for higher-capital-cost technologies.

Looking at the literature and calculating the LCOEs with extremes values for each input, one can demonstrate the wide range of LCOE estimates for each technology in a chart, available in the pdf of this talk. The main message is that the difference between the lowest and highest LCOE estimates for any type of plant range from about \$50 to several hundred dollars. The widest ranges are for rooftop solar and offshore wind, mostly driven with the wide range of CF across different locations. To get a sense of regional variability, I encourage listeners to visit the Full Cost of Electricity calculators available at the University of Texas at Austin Energy Institute web site. The Full Cost of Electricity project (<https://energy.utexas.edu/policy/fce>), calculators at <https://energy.utexas.edu/calculators>.

Importantly, existing resources have much lower LCOEs (basically their operating costs) than any new plant. Since they have no fuel cost and very low O&M costs, existing wind and solar plants have lowest cost generation, but those plants are mostly located where there is good wind speed and solar insolation (hence high CF).

In short, reported LCOE estimates are based on many assumptions that are not applicable at all locations and they do not take into account specifics of electricity systems. As such, generic LCOE estimates are not useful for system-specific analyses.

Wide range of recent levelized cost of electricity (LCOE) estimates, excluding externalities, system-integration costs, and subsidies (\$/MWh).



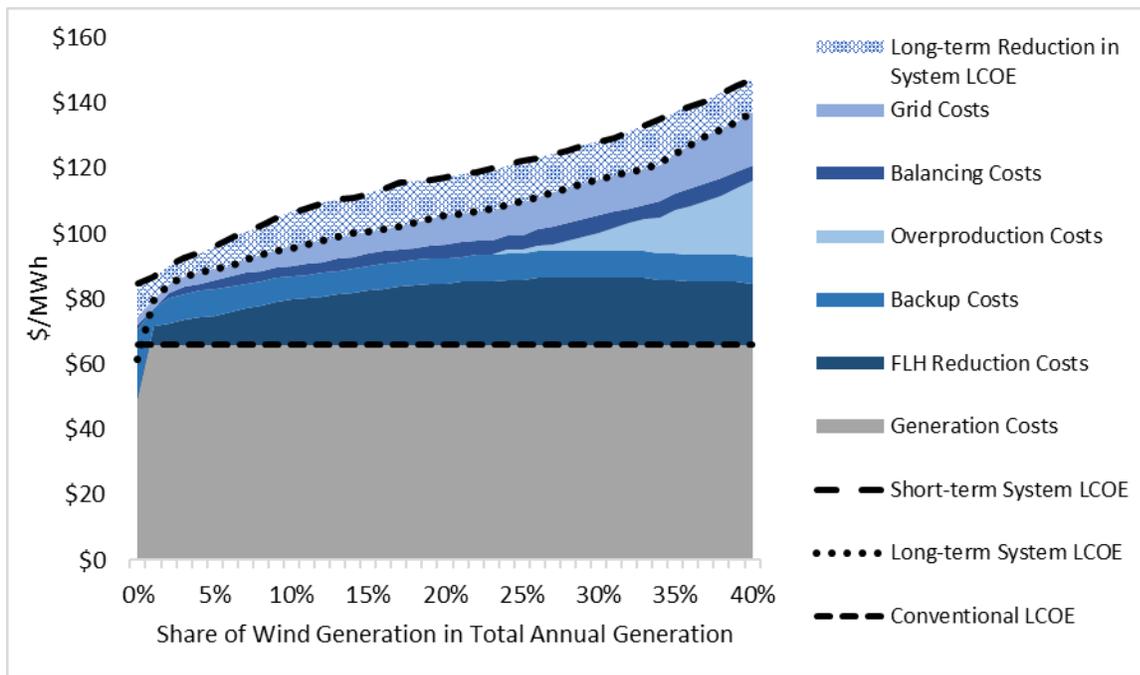
Source: Gülen, G. (2019), *Net Social Cost of Electricity: Policy Smog and Waning Competitive Markets, Lack of Consumer Participation, Importance of the Grid and Scalability Challenge*, Bureau of Economic Geology Udden Series No.7, 86 p., 21 figs, 5 tables, doi.org/10.23867/US0007D.

Sources are Lazard (2017, 2018a), the Energy Information Administration (EIA 2018c), and author's survey of literature. Gas peaking estimates from Lazard (2018a) are reported as natural gas combustion turbine (NGCT). Lazard (2017) provides \$82/MWh as midpoint of solar photovoltaic (PV) + storage, which was transformed into a range via +/- 20 percent. Coal IGCC (integrated gasification combined cycle), natural gas (NG) microturbine, and NGRE (natural gas reciprocating engine) are from Lazard (2017). The LCOE estimates for existing assets (outlined black) are by the author, except for nuclear from the NEI (2018).

LCOE is also inappropriate as a policy tool because they do not capture the cost of externalities, system integration costs, and cost of subsidies. After all, the main argument for supporting renewables is that they help reduce negative environmental impacts of our energy use. The environmental economics literature is pretty clear: federal tax credits and state RPS programs are less effective than direct taxation of the externality or an equivalent cap-and-trade market. But, since taxing externalities is politically unpalatable, subsidies and mandates are pursued. A social cost of electricity accounting needs to consider all relevant costs we pay either in our electricity, tax or health expenditures.

We pay system-integration costs of intermittent and variable resources in our electricity bills often in increased T&D charges or separate renewables charges but they also show up in energy costs. System integration costs include balancing and backup (or resource adequacy) costs, grid costs such as the T&D infrastructure needed to accommodate remote or distributed renewables, curtailment costs that are caused by capacity overbuild, and stranded costs of existing assets that are forced to lose revenues or even retire early because of subsidized resources. There is a growing literature on estimating these costs. In the pdf of this talk, I provide an adaptation of a chart from one of the pioneering analyses on this topic by Ueckerdt and others (2013) from Germany.

Wind-integration costs in a typical thermal system in Europe at various penetration levels.



Adapted from Ueckerdt and others (2013). Blue-shaded series represent various categories of system-integration costs (FLH = full-load hour reduction).

Different systems will experience these costs at different levels depending on their generation mix, load profiles, grid topography and connectivity, the pace of renewable capacity additions, type of renewable assets and whether they are utility-scale or distributed. But, generally, system integration costs will increase up to wind or solar penetration levels of about 30% of total generation and can be as high as the generic LCOE.

A related concept that is also getting more attention from researchers is the decline in market value of wind and solar. This decline is driven by the increasing penetration of wind or solar resources in the

same location increasing the mismatch between system load profile and wind generation. This is the natural outcome of intermittency of renewables. The issue can be larger with solar. I provide some references in the pdf of this talk, which indicate a value loss of up to 80% as penetration reaches 30%. It is easy to envision that a power system with too much wind and solar will require continuous subsidization of these resources, especially new builds, because they do not generate enough revenue from the market. Alternatively, a market-IRP approach (such as the one I proposed in my previous podcast) can decide on the least-cost portfolio of power system assets (i.e., a combination of generation, T&D and demand response) and costs will be reflected in regulated tariffs in our bills.

Sivaram and Kann (2016) report that when solar reaches 15 percent of generation in a system, its value falls by more than one-half. At 30 percent, a California simulation implies a value loss of more than 67 percent. Solar generation is highest closer to peak hours and curtails the peak prices. The daily peaks shift to early evening hours, but prices are not as high during those hours. The challenge is universal. Hirth (2015) concludes that solar value is higher than average wholesale price at low penetration, but this benefit turns into a penalty as penetration surpasses 5 percent in the case of Germany. Hirth (2015) also suggests that this value drop is steeper than wind's value drop because solar generation is more concentrated and coincides with high demand periods. Hirth (2013, p. 218) finds "the value of wind power to fall from 110% of the average power price to 50%–80% as wind penetration increases from zero to 30% of total electricity consumption."

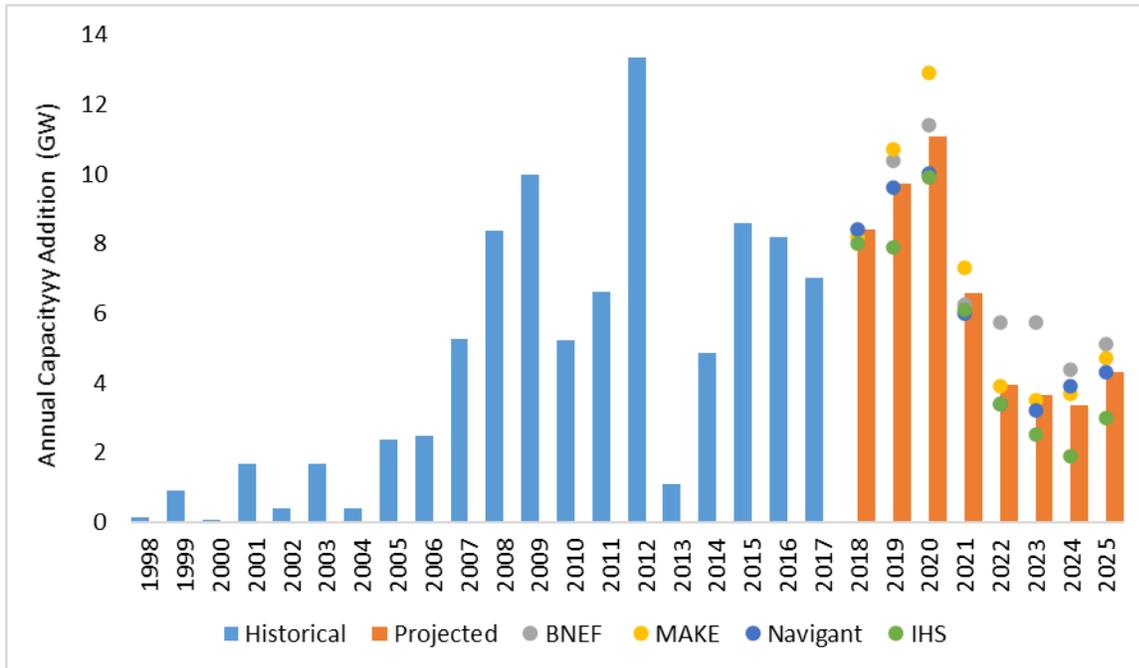
Finally, in addition to costs associated with externalities and system integration of intermittent resources, we must consider the cost of subsidies. The topic of subsidies is emotional and political. The willingness of governments to offer them certainly feeds rent-seeking behavior; encourages inefficiency in capital expenditures, production, and consumption of subsidized goods or services; and undermines competitive markets. Importantly, they lead to "leveling the playing field" arguments by competing interests and hence more inefficiencies and waste. For example, several states subsidized select nuclear plants to prevent early retirement. I cannot go into details of the subsidies debate in this talk but I refer listeners to the section on subsidies in my report [Net Social Cost of Electricity](#).

Adding costs of externalities, system integration and federal subsidies, we can augment the generic LCOE estimate. Note that this augmentation does not eliminate the need for looking at LCOE at different regions. I encourage the listeners to peruse the chart I provide in the pdf. This chart is incomplete, missing some externalities and state level subsidies. Still, some general observations are possible. The competitiveness of technologies changes when we consider these additional costs with a couple of exceptions. Coal cannot compete with the high cost of externalities even with CCS. Nuclear is the cheapest option: nearly no externalities, very limited per-MWh subsidies, relatively low fuel cost and 90% CF compensate for large CAPEX. Saving existing nuclear plants with subsidies in the range of \$10-20/MWh does not change this conclusion.

Importantly, wind and solar can be cheaper than alternatives in many locations but not everywhere. The unqualified reporting in the industry and public media that "wind and solar are already cheaper than alternatives" is the worst side effect of promoting the flawed LCOE metric. Such blanket statements are technically incorrect. As I mentioned before, we can see the total costs in our increasing retail bills that reflect much of the system integration costs. And, we can see that subsidies to wind and solar are not discontinued, practically nowhere in the world. Every time a major subsidy was cut, capacity installations declined significantly. For examples, please see the history of PTC expiration and wind

capacity builds in the US (see chart below) and what happened in several European countries that cut the subsidies after the 2008 financial crisis.

Historical and forecast US wind-capacity additions.

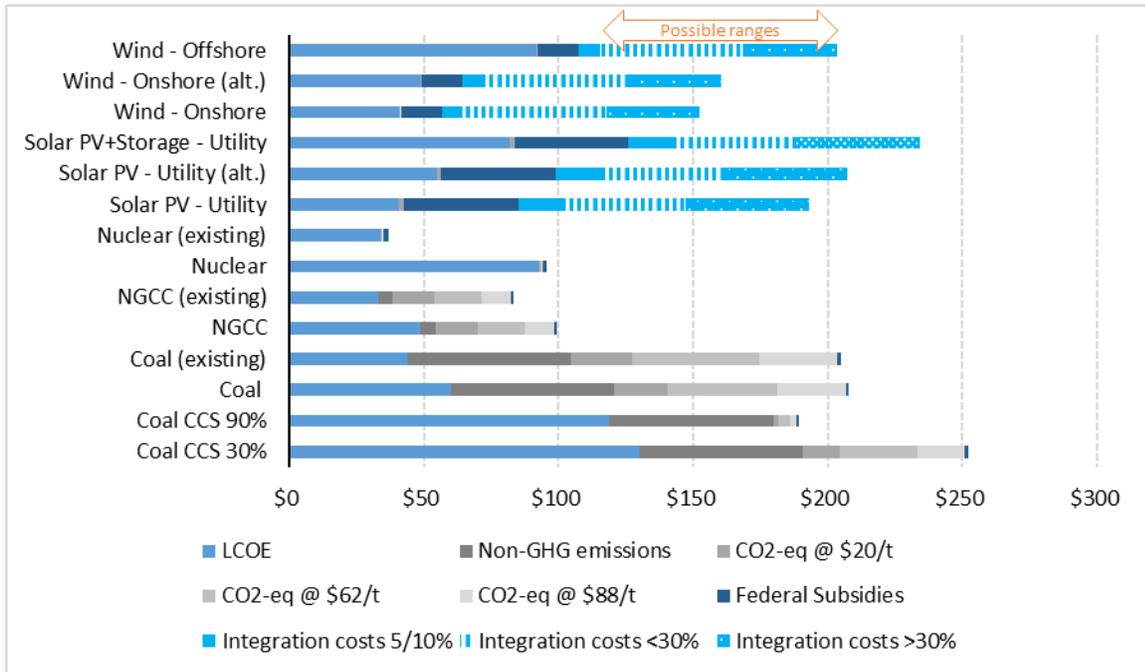


This chart recreates figure 59 of Wiser and Bolinger (2018). Forecasts by Bloomberg New Energy Finance (BNEF); MAKE; Navigant; and IHS Markit (IHS).

In summary, the generic LCOE does not help develop a rational energy policy because it does not capture electric power system realities. As an improvement, the system LCOE should replace the generic LCOE with system-specific calculations. For policy discussions, though, even the system LCOE has to be augmented to reflect the costs of externalities and subsidies. Only then, we have a useful, albeit still imperfect metric, on which we can base discussions about a least-cost portfolio approach to transitioning electric power systems to achieve environmental and consumer goals.

Thanks for listening.

Representative US LCOE with air emissions, system-integration costs, and federal direct and tax subsidies (\$/MWh).



Excludes negative externalities associated with water, land, ecological impacts; positive externalities; non-federal subsidies; and federal subsidies other than direct and tax expenditures. These comparisons should not be extrapolated to any project in any location. The base LCOEs are only valid for “average” US locations where it is feasible to build any of these plants. State-level subsidies differ. The LCOE is a high-level policy discussion tool. Developers do not use LCOE for investment decisions. It is not recommended for the market-IRP.

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