An Insider's Guide to the Calculation and Use of LCOEs

Although metrics like the levelized cost of electricity (LCOE) have generated controversy, these criticisms are not necessarily about LCOE metrics per se but instead reflect how LCOE is used in analyses of the economic viability of variable renewables and their competitiveness with dispatchable generators.

What makes the LCOE metric useful is that it combines investment and operating costs and plant performance into a single metric that can be compared with projects that have different lifetimes and cost structures. Also contributing to LCOE's widespread use is its ease to calculate, requiring only a few key inputs to determine anticipated costs averaged over a project's lifetime output.

LCOE makes no pretense of measuring value, system costs, or the relative economic competitiveness of different resources but is criticized when analysts and policymakers ignore these limitations. For instance, the competitiveness of existing coal and gas plants vis-à-vis new variable renewables cannot be assessed by comparing the dispatch costs of the former with the LCOE of the latter. LCOE can be a convenient summary statistic for evaluating cost changes over time, but it is well known that actual **decisionmakers use more complete and analytically rigorous modeling frameworks** for energy resource decisions.

Value Is Hard

For decision-making and policy analyses, **value is much harder to quantify given uncertainties about the future and system interactions**. How will hourly power prices evolve over the next 25 years? What will be the daily gas prices, future renewals of tax credits, policy requirements, rates of renewable cost declines, and significant technological advances over that timeframe? What will a renewable energy certificate (REC) be worth over a project's lifetime?

This uncertainty implies risks to project and PPA owners, but it is not necessarily a limitation of LCOE. Problems arise when analysts get the value side wrong, assume the present will go on forever, or omit value differences altogether. **Value and cost calculations are also location-, context-, and system-specific**, which can complicate calculations and limit generalizations from specific analyses.

Observations on LCOE Use

Key inputs matter in LCOE calculations, so analysts should be transparent about these choices before they use or communicate them. For wind and solar, perhaps the greatest impact is whether the LCOE calculation includes subsidies and policy support (e.g., tax credits), followed by the source of capacity factors (e.g., "best-in-class," local estimates, future curtailment assessments). Either choice has the potential to double or halve the calculated LCOE.

Also important is how much the cost inputs reflect ongoing declines. Solar project costs have been decreasing at about 13% per year since 2010, while wind project cost have been declining at about 6% per year over the same period. Whether the LCOE represents current costs or those two years from now can make a 10 to 20% difference in value.

LCOEs are best understood as the collected assumptions of an analyst instead of as factual technological parameters. A good rule of thumb in using LCOEs is to use input assumptions representative of local projects currently being deployed. Power purchase agreements (PPAs) reflect contractual terms, and the lack of transparency in public announcements make LCOE inputs (e.g., capital costs) difficult to infer with precision based on PPA prices alone. Note that PPAs involving a mix of solar and storage can be particularly challenging to unbundle to find the underlying LCOE.

Value Proposition of Variable Renewable Energy

Variable renewable project viability depends on the energy and REC market values being sufficient to cover the LCOE. The going-ahead requirement can be stated as:

$$\text{Energy Value} + \text{REC Value} \geq \text{LCOE (all in \$/MWh)}$$

Formally, the energy market value is the NPV of the sum of anticipated hourly power prices multiplied by the expected hourly output, divided by the NPV of the output, all over the project's lifetime. This calculation is not easy, but energy value is the key source of value for many if not most projects. As described in the next section, projects can also earn capacity revenue depending on market rules and alignment between wind and solar output and residual peak demand. However, the capacity contribution of variable renewables is typically lower than dispatchable generators and declines at higher penetration levels, which makes this value stream comparatively small in many instances.

Renewables also earn REC value, representing the value of the environmental attributes. Whether the requirement is formal policy or voluntary, REC value is essentially the shadow price of meeting the constraint. If energy revenues fall, then the REC value must rise to meet the difference for going-forward revenues to exceed costs.

Value Proposition of Existing Generators

The value of dispatchable generation is based on the sum of energy market value (as calculated above), capacity value (which may be embedded in the energy value or earned in formal capacity markets), and ancillary services value (which also may be at least partially captured in energy market value). The survivability proposition for existing capacity (i.e., what it needs to keep operating instead of retiring) depends on market revenues and fixed operations and maintenance (FOM) costs:

$$\text{Energy value} + \text{Capacity Value} + \text{Ancillary Services Value} \geq \text{FOM (all in \$/kW)}$$

The average energy value is the NPV of hourly prices minus hourly dispatch prices, summed over the hours when the margin is positive, over the unit's remaining lifetime. Here, we need to know the hourly prices over time, and the hourly dispatch prices, which are driven primarily by fuel prices that could vary on a daily, monthly, and annual basis.

For non-dispatchable generation without the flexibility of adjusting output based on market prices, the calculation is easier. These resources essentially operate over all hours of the year, so the annual margin can be calculated based on the average price minus the average variable operating cost. This is the one exception to estimating energy value that does not require information about hourly price distributions.

Putting Value Estimation into Practice

The challenge is that valuation of variable renewables and dispatchable generators requires knowing the hourly power prices over remaining lifetimes. This information is both difficult to acquire (for historical data and prospective systems), and difficult to work with when acquired. Any such forecasts must be assumed to have high margins of error.

Recent hourly price histories can provide an initial screen for valuation. If the project or asset is not worth building (or keeping) based on current hourly price distributions, then there should be a compelling rationale for why future price distributions will be more favorable.

The California Independent System Operator (CAISO) provides hourly data on power prices and renewable output over the last decade (Source: Energy Velocity Suite). This dataset demonstrates the value calculations described above and provides insights into the importance of estimating value based on hourly price distributions instead of annual averages. The sequential and sorted prices for 2018 are illustrated in Figure 1. The average hourly price (unweighted) in this data is $36.50/MWh. The highest price was $999/MWh, while the lowest was -$19/MWh. 251 of the hours saw negative prices. The distribution is highly skewed, with prices below the average for over 70% of the hours.

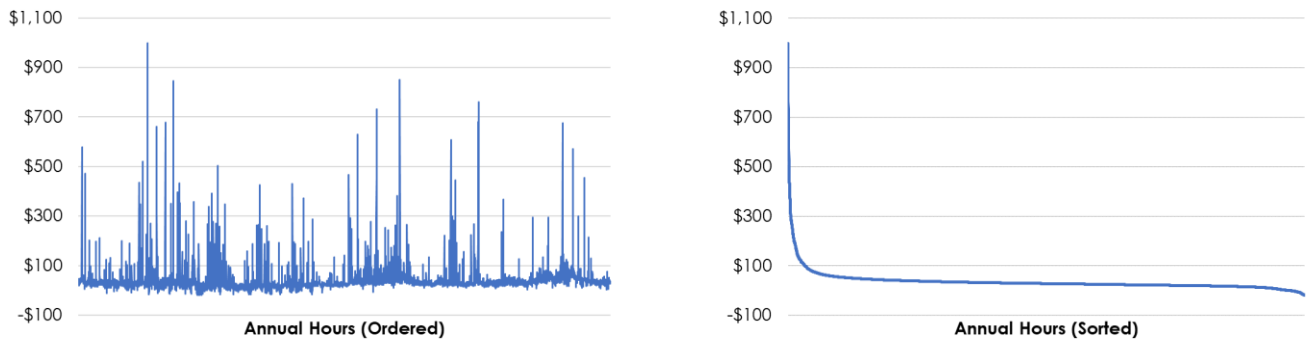

Figure 1: *Sequential (left) and sorted (right) hourly electricity prices ($/MWh) for CAISO in 2018. Values are averages of the SP15 (Southern California) and NP15 (Northern California) areas.*

The corresponding energy values for wind and solar in CAISO are presented in Table 1. Calculated as the output-weighted average of power prices, the 2018 results show different values for wind and solar in the same power market. The energy value for an average solar MWh ($27.6/MWh) is $6.1 less than the value for an average wind MWh ($33.7/MWh), and both are worth less than the overall average price ($35.8/MWh). For a utility covering load, the load-weighted average electricity price is $38/MWh, much higher than the variable renewable values. The wind and solar values likely exceed the subsidized LCOEs for projects starting that year, so in this case, the REC value is zero. Calculating wind and solar energy values is a straightforward spreadsheet exercise, with hourly data on power prices and renewable output, but these calculations require considerably more effort than casual back-of-the-envelope calculations like LCOEs.

We can also estimate the 2018 energy value for dispatchable gas generators: combined cycle, gas turbines, and steam. Using California average dispatch costs ($23.1/MWh for combined cycles, $41.9/MWh for gas turbines, and $35.6/MWh for steam), we can add up the value of hourly prices higher than these dispatch costs for the year, and divide by the capacity to get annual energy market value for each. In this example, the combined cycles had an energy market value of $135/kW-yr, the gas turbines had a value of $71/kW-yr, and the gas steam had a value of $84/kW-yr. These values are well above annual FOM costs for these technologies, though environmental and physical operating constraints may limit achieving these potentials in practice.

Table 1: *Energy market value of wind, solar, and other generation for CAISO in 2018. Values are output-weighted average prices and quantities.*

	Price ($/MWh)	Hourly Avg. (%)	TWh
Solar	27.6	77%	27.8
Wind	33.7	94%	16.5
Load	38.0	106%	226.7
Average	35.8		

Representing the Future Is Hard

Calculating the "first year" value propositions with recent hourly market and output only offers a quick screen for value. While it is convenient to extrapolate future values from recent history, such simplified approaches likely provide misleading insights.

The future will be different due to uncertainty in key drivers (e.g., natural gas prices, rate of variable renewable technical progress, evolving policy goals, renewals of subsidies), all of which can impact future power markets and asset valuation.[1] Sensitivity analysis can inform stakeholders on the consequences of these uncertainties but cannot forecast the future. Conducting these sensitivity analyses over the timeframes needed for **valuation requires capacity planning and dispatch modeling frameworks**.

The other need for long-term system models is to understand the interplay of market forces that can make the future **systematically** different than the

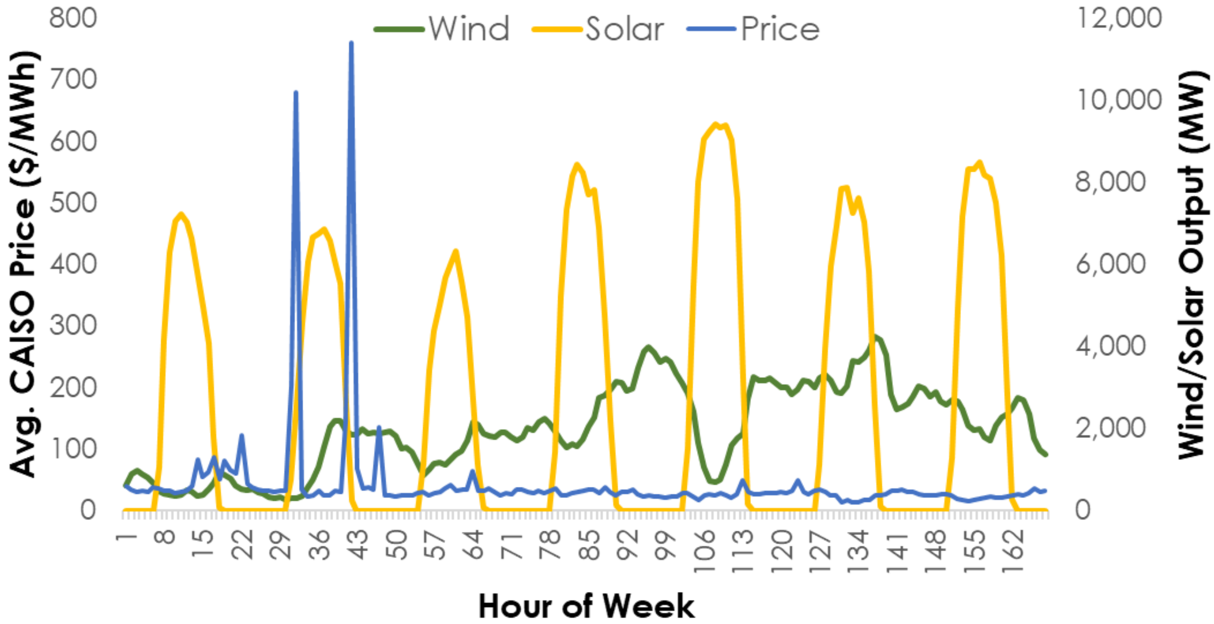

***Figure 2:** Hourly electricity prices and variable renewable output for CAISO in 2018 (Week 40 shows energy market "ramp spikes").*

present. Particularly relevant for variable renewables is the concept of **value deflation, where increasing deployment of wind and solar erodes energy market value by cutting prices during hours when wind and solar output is highest**. The phenomenon is well supported by simulation-based analyses[2] and empirical analyses of high wind and solar markets.[3]

The CAISO experience is indicative of deflation for solar. Solar's energy value went from commanding a 22% premium over the average market price in 2012 to a discount of 23% in 2018. During this period, utility-scale solar output increased from 2 TWh to 28 TWh (increases in solar were even greater counting behind-the-meter installations, but data are sparse). However, the value of wind increased slightly over this same time period, despite a 75% increase in output. Such differences in value explain why wind might be preferred to solar in specific settings, even when solar costs are lower.[4] This example further supports the complexities involved and need for detailed modeling.

The effects of value deflation are real but all but impossible to quantify without careful simulation of the dynamics of energy market price formation and simultaneous impacts on the economics of variable renewable investments. The economic value of renewables changes based on the state of the system, and LCOEs for dispatchable generation face uncertainty about capacity factors from system changes such as higher wind and solar deployment.

There is a parallel dynamic for assessing the effects of renewables on the viability of existing dispatchable generation. Power prices generally decline and have increased numbers of zero or negative values with higher wind and solar penetration, but viability depends on the value mass at the upper end of the price distribution. The highest prices occur when the system is short of capacity, conceptually defined as "iron on the ground that does what it's told when asked." Sometimes the need is to meet peak residual loads (i.e., demand less wind and solar output), but the 2018 CAISO data show many spikes associated with ramping needs, as shown in Figure 2. A surplus of capacity can lower price spikes and mass in the upper tail, and the low-price mass will impact the viability of existing generation. More retirements mean less capacity which means more price mass in the capacity-short periods. These self-correcting processes of entry and exit are fundamental characteristics of power markets but are difficult to quantify without careful modeling of the market dynamics.

Key Insights on Interplay of LCOE and Value in Evolution of Markets with Declining Renewable Costs

- Declines in wind and solar costs due to technological progress and policy support lead to increases in variable renewables, but this deployment leads to value deflation until the marginal resource's LCOE equals its market value.
- While we need long-term capacity planning and dispatch models to evaluate when this condition is satisfied, the ultimate effect is lower average prices and hours with near-zero or negative prices.
- With binding renewable requirements, the process continues until the requirements are met where the LCOE equals the sum of energy and REC value. As a consequence, wholesale prices will decline further, with even more hours of zero or negative prices.
- The economics of dispatchable generation depends on how evolving price patterns maintain "value mass" in the hours of low wind and solar output sufficient to cover their FOM cost threshold. Much of the existing dispatchable fleet may remain viable, as long as it is needed to cover occasional hours of the year when wind and solar are unable to serve load or to support ramping and ancillary services needs.
- Less flexible generators, however, will see the deeper drops in energy value and, with high FOM, will see reduced viability without offsetting policy support.

Summary

LCOE is barely more than a back-of-the-envelope calculation but still does a good job of capturing project cost, especially for wind and solar. However, appropriate interpretations of LCOE metrics are critical. **Levelized-cost metrics are insufficient for evaluating the economic competitiveness of different power sector resources, as they do not evaluate how the market value and ancillary system costs of technologies vary as the state of the system evolves over their futures.** Value is determined in markets that face many uncertainties and the interplay of offsetting forces and feedback loops. **Long-term capacity planning and dispatch models provide a laboratory for understanding the uncertainties, value dynamics, and system costs but require much more computational effort.** And, in the end, the future is still uncertain.

Contact Information

For more information, contact Victor Niemeyer (e.v.niemeyer@gmail.com) or John Bistline (jbistline@epri.com).

[1] Levelized-cost measures typically do not account for uncertainty or flexibility: Bistline, et al. (2018). "Managerial Flexibility in Levelized Cost Measures: A Framework for Incorporating Uncertainty in Energy Investment Decisions," *Energy*.

[2] "A Primer on Wind and Solar Value Deflation," EPRI Program 201 Back Pocket Insights.

[3] Mills, et al. (2019). *Impact of Wind, Solar, and Other Factors on Wholesale Power Prices: An Historical Analysis—2008 through 2017* (LBNL, Berkeley, CA).

[4] Bistline, et al. (2018). "Electric Sector Policy, Technological Change, and U.S. Emissions Reductions Goals: Results from the EMF 32 Model Intercomparison Project." *Energy Economics*.

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Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com