RESOURCES for the FUTURE

The Changing Costs and Values of Electricity Generation Technologies: Measuring Profitability and Evaluating Options for Integrating Renewables

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The US electricity sector has been a favorable area for reductions in carbon dioxide emissions, with CO_2 from the power sector decreasing by **28% between 2005 and 2017**. In addition to slightly lower electricity **demand**, the sources of CO_2 emissions reduction have been the substitution between different fossil fuels (mostly of natural gas for coal-fired power) and the installation of zero-carbon generation capacity (mostly wind and solar). The relative profitability of existing power plants and the expected profitability of new installations explain much of the recent trend in decarbonization and, along with demand growth, will determine future electricity sector emissions. Measuring the profitability of electricity-generation technologies requires accounting for their values as well as their costs.[1] In this brief, we examine two approaches to assessing costs and values, first considering the cost and value of an individual power plant, and then considering the cost of a power plant to the entire electricity system.[2] The dual approaches yield insights into the changing composition of power generation, often unseen system costs, and the likely effects of grid integration options, such as energy storage.

Individual Approach: The Cost and Value of a Single Power Plant

An individual power plant's profitability is a market determination of the value less the cost of the plant's generation. Power generation costs fall into five general categories (four are listed in the subsection below, and the fifth is discussed later in this section). Adding up those costs informs whether an existing plant will generate electricity, whether an existing plant will earn operating profits, and whether a new power plant is likely to be constructed. Generation value is composed predominantly of energy and capacity values, which together provide the market revenue available to the power plant.

Power Generation Costs

Total Costs
Operating Costs
Variable Costs

1. **Fuel costs** are the costs per megawatt-hour (MWh) of electricity generation for fuel and the resulting emissions. These costs depend on the price of the fuel delivered to the plant, the efficiency at which the fuel is converted into power, and charges for emissions of CO_2, SO_2, or NO_X (if such charges exist).
2. **Variable operations and maintenance (O&M) costs** are the costs of power plant operations and maintenance incurred due to electricity production. Power equipment may deteriorate more quickly when generating electricity than when the plant is idle, requiring increased repair or replacement of parts.
3. **Fixed O&M costs** are the costs of power plant operations and maintenance that are incurred whether or not the power plant is generating electricity (for example, the costs of regular maintenance, monitoring, and inspection).
4. **Capital costs** are the costs of power plant development and construction. They are incurred before the plant produces electricity and consist of equipment (including emissions reduction equipment), installation and construction labor, permitting and interconnection costs, and contractor overhead.

For existing facilities, only the variable costs—fuel and variable O&M costs—are relevant to which power plants will produce at a given time. Solar and wind have no fuel or variable O&M costs, so they will generate power whenever the sun shines or wind blows (as long as they do not need to be curtailed).[3] Additionally, changes in fuel costs have altered the utilization of existing fossil power plants. Whereas Henry Hub natural gas prices were generally above $6/MMBtu between 2005 and 2008, they have averaged less than half that amount over the past **four years**. As a consequence, average utilization (known as the capacity factor) of natural gas combined-cycle generators has increased from **35% in 2005 to 58% in 2018**; meanwhile the capacity factor of coal plants declined from 67 to 54% over this period. With the CO_2 intensity of coal-fired power **roughly twice** that of natural gas combined-cycle generation, the increased utilization of natural gas and decreased utilization of coal have been significant factors in recent emissions reductions.

For unbuilt power plants, all four cost categories are relevant when gauging the expected future profitability of the plant. Moreover, since different generation technologies incur their costs at different times (e.g., solar and wind have large capital costs but no fuel or variable O&M costs), it is necessary to compare all costs in terms of present discounted values over the expected operating life of the plant. The common metric, levelized cost of electricity (LCOE), does exactly that:

$$\text{Levelized Cost of Electricity (LCOE)} = \frac{\text{Present Value of All Plant Costs}}{\text{Present Value of Electricity Generation}} = \frac{\$}{\text{MWh}}$$

Since all costs and electricity are discounted to their present values, LCOE involves a fifth category, the cost of capital, which determines the rate at which both costs and electricity production are discounted over time. For example, a technology with a high cost of capital will have a lower present value of electricity and thus a higher LCOE. Further, more electricity production reduces LCOE, so a plant that operates more often or with greater efficiency will have lower levelized costs.

If all generation technologies were dispatchable—capable of producing electricity at any time—or if the price of electricity were constant, LCOE would be a reasonable proxy for the profitability of different technologies. However, since solar and wind are intermittent generators and the price of electricity does vary over time, **LCOE is inadequate for comparing intermittent technologies** with each other or with dispatchable technologies such as natural gas.

Power Generation Value

In addition to considering costs, we also need to assess the prices that a power plant will receive for its electricity output. Wholesale power prices indicate the energy value available to power plants. Although there is variation in how frequently and at what geographic scale wholesale power prices are determined, the wholesale power price is generally a time- and location-specific value of electricity. Such prices suggest the current energy revenue that a plant could realize, but the relevant prices for new plants are those that will occur over the next 20 to 30 years (the lifetime of most power plants). Forecast time- and location-specific prices would be essential for a project developer, but these projections would not provide a geographically broad measurement of the future energy value for a particular type of power generation. Additionally, in many regions of the country, power plants receive capacity payments for their contribution to grid reliability, which must be included in a complete measurement of value.[4]

The US Energy Information Administration (EIA) developed a measurement of the value available to a new power plant. **EIA's levelized avoided cost of electricity (LACE)** is an estimate of the cost of providing energy and capacity to the grid that would be avoided (or displaced) if the new power plant were to operate. The avoided cost to the grid is equal to the revenue available to the power plant, so LACE provides an assessment of potential plant revenues. While LACE is not used by EIA to determine capacity additions, outputs of EIA's National Energy Modeling System (NEMS) are used in LACE calculations.

$$\text{Levelized Avoided Cost of Electricity (LACE)} = \frac{\text{Present Value of Energy and Capacity Revenue}}{\text{Present Value of Electricity Generation}} = \frac{\$}{\text{MWh}}$$

Energy revenue for a particular time period (e.g., summer daytime) is estimated by multiplying the forecast electricity price by the annual number of megawatt hours of electricity the plant is expected to generate during that time. Energy revenue would also include the price of meeting environmental policies, such as a state's renewable portfolio standard, if the generator displaced is nonrenewable. Annual energy revenue is the sum of energy revenue for each time period across the year (**EIA uses nine time periods**). Capacity revenue is the capacity payment, the amount necessary to achieve system reliability, times the percentage capacity credit. In LACE, dispatchable plants are given a capacity credit of 100%, but intermittent renewables receive less than 100% based on their ability to **reliably provide capacity**. Total revenues (energy plus capacity) and electricity generated are discounted to their present values at the plant's cost of capital, giving LACE the same units ($/MWh) as LCOE.[5]

Value-Cost Comparison

A power plant is profitable if the market value of its generation exceeds its costs of producing that electricity. An existing plant will generate whenever prices exceed variable costs, and it will have operating profits if prices exceed all operating costs (fuel and variable O&M costs, as well as fixed O&M costs). For a prospective plant, investors would require that expected future prices exceed LCOE by a sufficient margin in order to commit financing. While developers of a prospective plant would make an estimated value-cost comparison at a specific location, EIA presents more general measures of profitability by computing value-cost ratios (LACE/LCOE) in each of the 22 electricity supply regions of the United States represented in the NEMS Electricity Market Model. The minimum, maximum, simple average, and capacity-weighted average LACE/LCOE ratios indicate how likely a particular generation technology is to be installed, as well as the geographic extent of its profitability.

System Approach: The Generation and Integration Costs of a Power Plant

An alternative approach to assessing the net value of a new plant is a **system approach** that takes the perspective of a social planner, assessing the total costs that an additional power plant would have on the electricity system. The total system cost combines a new plant's generation cost with the cost it imposes on existing plants and the grid itself—its integration cost. The generation cost of a power plant to the system is identical to the generation cost of the power plant to itself. Since all components of generation cost are relevant, LCOE is the appropriate metric.

The individual and system approaches diverge with respect to integration costs. Whereas the individual approach relies on market values to reflect diminishing values of generation to the grid, the system approach makes a direct evaluation of integration costs. Just as intermittent technologies require market values, in addition to LCOE, to assess their profitability, intermittent technologies impose additional integration costs that must be included in their system costs. Dispatchable plants also impose **integration costs**, but the integration costs of intermittent technologies increase more rapidly with greater penetrations of intermittent generation. Additionally, the trade-offs between minimizing integration costs and generation costs are less significant for most dispatchable plants. For example, the ranges in average **2021 LCOE** in EIA's 22 regions are $38.1–$48.5/MWh for natural gas advanced combined cycle versus $41.7–$111.6/MWh for unsubsidized solar photovoltaic (PV) projects. Whereas natural gas plants can be sited to minimize integration costs with only minor effects on LCOE, the same is not true for solar—solar LCOE is highly sensitive to location.

Plant Integration Costs

To provide a complete measurement, the integration costs of an additional power plant must include all costs borne by the system that result from the plant's installation. Various **bottom-up estimates of wind and solar integration costs** capture the costs of managing the variability of wind and solar, but engineering estimates may miss other economic costs that are relevant to integration. A full accounting of integration costs of any additional plant (dispatchable or intermittent) comprises the following five categories, each of varying significance based on such factors as the technology, resource availability, transmission network, load profile, storage capacity, and generation mix. Integration costs may occur in the short term (before the grid has fully adjusted following the plant's installation) or over the long term. Lastly, integration costs are those due to new generation rather than to changes in demand. Transmission expenditures, for instance, may rise with growing electricity demand in a particular location, but such costs would not be due to plant integration.

1. **Balancing costs** are the costs of managing the unpredictability of generation. Wind and solar have both predictable and unpredictable components of their variability—solar will predictably not generate at night, but it will unpredictably reduce output if a daytime hour is unexpectedly cloudy.
2. **Grid/transmission costs** are the costs of building transmission to an area with high-quality energy resources, as well as increasing transmission capacity in an area where a new power plant causes grid congestion.
3. **Adequacy/backup costs** are the costs incurred by the system because certain existing generators, which would retire if the new plant were dispatchable rather than intermittent, are kept online to provide adequate capacity to the grid. Adequacy costs reflect redundancy of capacity, and they vary inversely with the **reliable capacity** that the new plant is able to provide to the grid.
4. **Curtailment/overproduction costs** are the costs from power generation that cannot be used on the grid and thus is wasted.[6] Curtailment causes plant electricity production to decline and **thereby LCOE to rise**. Since curtailment is a function of the grid, rather than the power plant, curtailment costs are a component of integration costs.
5. **Residual generation costs** are primarily the costs to the existing fleet of running at a lower capacity because of the addition of a power plant. Whereas adequacy costs reflect fleet redundancy, residual generation costs reflect inefficiency in fleet operations. Such costs are significant for a new wind or solar plant, which has no variable costs and thus is often first in line to produce power for the grid. Consequently, other generators—such as coal and natural gas—will produce less electricity, increasing their LCOE. If such a plant becomes unprofitable and retires prematurely, there will be a cost from the "stranded asset"—borne by **ratepayers, generators, and distribution companies**—which may be a significant short-term cost (in the long term, retired plants no longer impose costs on the system). A secondary cost in this category is due to increased cycling of coal and gas plants because of predictable variation in intermittent generation. Cycling—the ramping up and down of production—increases O&M costs for generators, but these expenses appear to be **minor** in comparison to the costs of operating at reduced capacity and from stranded assets.

While these cost categories are not fully independent of each other (transmission costs and curtailment costs are an obvious example of interdependence), considering the cost components reveals how plant integration cost might be reduced. The total system cost of a power plant is simply the sum of its levelized generation and integration costs.

Comparing the Individual and System Approaches

The individual and system perspectives provide different information, and each is useful.[7] Both approaches use widely available generation cost information, but the individual approach also uses market values (or proxies for market values, such as LACE). The individual approach to estimating plant profitability is thus fully based on market data and expectations, and the calculation adjusts to changing market conditions (however, with project lifetimes of

20 years or more, estimates of future values are highly uncertain). As detailed in the next section, quantifying the costs and values of a generation technology over time provides an estimate of its evolving social value. However, the individual approach does not reveal the causes and magnitudes of increased system costs due to adding intermittent renewables. The five integration cost categories describe why system costs would rise, and system models estimate integration costs at varying percentages of renewables on the grid. In doing so, the system approach informs which prospective grid changes could mitigate future integration costs.

Declining Costs and Values of Solar and Wind Generation

Generation Costs

Over the past decade, the generation costs of solar and wind have fallen dramatically. The financial institution Lazard has provided LCOE estimates for wind and utility-scale solar PV (among other technologies) for the past dozen years, using ranges of capital cost, O&M cost, capacity factor, and discount rate assumptions. The firm's mean estimates for unsubsidized wind and solar LCOE fell from **$135/MWh and $359/MWh**, respectively, in 2009 to each being just $43/MWh in 2018, implying cost reductions of 69% for wind and 88% for solar over the past nine years. Future reductions in generation costs are expected, albeit at a more modest rate. In its Annual Technology Baseline, the National Renewable Energy Laboratory (NREL) projects that the unsubsidized LCOE of utility-scale solar in a moderately sunny location (Kansas City) and with midpoint assumptions will decline from **$37/MWh in 2018 to $25/MWh in 2040**. For wind, using a mid-category wind resource and average assumptions, NREL projects that unsubsidized LCOE will decrease from $42/MWh to $31/MWh over this period.

Generation Values

A simple but incomplete measure of generation value for a power plant is average wholesale electricity prices, weighted by the hourly amount of its generation. Lawrence Berkeley National Laboratory (LBNL) analyses of 2017 data found average regional electricity prices for wind of **$14–$28/MWh** across the country and an average solar price of **$25/MWh** in California. Although these prices are below the average LCOE for wind and solar, these projects also receive tax credits and deductions, and they may additionally receive revenue from capacity markets or value from renewable energy certificates (or RECs, the environmental attributes of their electricity). More concerning than the low wholesale prices are their trends, particularly for solar. In an **analysis of the California market** from 2012 to 2016, the authors found that the 10,000th MW of solar earns 52% less energy revenue than the 2,000th MW and that the 6,000th MW of wind earns 20% less energy revenue than the 1,000th MW; hourly prices fall as solar and wind additions displace generation with higher variable costs. Projected values show further declines with increasing solar and wind penetration; an **LBNL study of California** found that a 30% penetration of solar would result in a 72% decrease in its marginal economic value (inclusive of values from energy, capacity, and ancillary services) and that a 40% penetration of wind would result in a 40% decrease in its marginal economic value. Although solar initially receives above-average prices because of high electricity demand in the afternoon, the midday-concentrated generation profile of solar causes its prices to erode rapidly with increased penetration (a consequence of the "**duck curve**").

Generator Profitability

To provide a countrywide assessment of current and future generator profitability, EIA publishes **ratios of LACE to LCOE** for plants installed in the near term (2021 and 2023) as well as for plants installed in 2040. In these ratios, LCOE includes any federal tax credits available in the particular year, and LACE includes capacity revenue as well as energy revenue. Moreover, energy revenue in LACE includes the cost of meeting a state's renewable portfolio standard (RPS) if the generation displaced is nonrenewable (e.g., a natural gas generator in an RPS state would have to purchase RECs). A ratio greater than 1 indicates that the projected revenue available to a new power plant (LACE) exceeds its cost (LCOE), so an installation would expect to be profitable. For plants entering service in 2021, the LACE/LCOE ratios in the 22 EIA regions range from 0.6 to 1.23 for wind and from 0.61 to 1.20 for solar. For plants entering service in 2040, LACE/LCOE ranges from 0.63 to 1.08 for wind and 0.69

to 1.19 for solar. As EIA projects only moderate decreases in wind and solar costs (which are offset by declining tax credits) and small shifts in value, the profitability ratios do not change substantially.[8]

Integration Costs and Opportunities for Reductions

The system cost approach allows us to evaluate various solutions that have been proposed for integrating intermittent generation. First, it is useful to review some modeled and empirical results on the magnitude of total integration costs and their components. **In a 2013 modeled European grid**, total integration costs for wind are roughly €40/MWh when the proportion of wind generation reaches 25% (in comparison, the LCOE of German wind in optimal locations was €60/MWh). Of this total, about one-third of integration costs are due to balancing and transmission needs, while the other two-thirds are the result of backup and residual generation costs. Curtailment costs become significant only for wind generation greater than 25%, but they grow rapidly beyond that point. **For solar in Arizona**, similar integration costs are estimated; 20% penetration of solar would cause $6/MWh in losses due to unpredictable intermittency (balancing costs) and $40/MWh in losses due to predictable intermittency (backup and residual generation costs). Finally, **in recent research on US RPS policies**, retail electricity prices 7 and 12 years after passage of an RPS are found to be 11% and 17% higher, respectively. Since differences in generation costs between renewables and nonrenewables cannot explain the price increases, the authors conclude that integration costs are a probable cause of rising system costs.[9] With an understanding of integration costs and the relative importance of each category, Table 1 lists options for plant integration and their prospective effects on the costs of integrating intermittent renewables.

The assessments of plant integration options in Table 1, in combination with the estimates of integration costs, indicate both the areas with the largest potential for cost reductions and the potential solutions that are most likely to be effective. From the integration cost studies, balancing costs both are comparatively modest and do not increase substantially with rising proportions of intermittent renewables. Grid costs are more significant than balancing costs and increase with renewables' penetration, but costs spent on transmission allow for accessing high-quality solar and wind resources and limiting curtailment. Thus there is a trade-off between higher grid costs and lower generation costs (LCOE) and curtailment costs. The last three integration cost categories—adequacy, curtailment, and residual generation costs—together have the greatest opportunity for total system cost reduction, and increasingly so as intermittent renewables expand their share of generation. Among the options, flexible demand and energy storage have the potential to significantly reduce costs in all three of these categories. In regard to energy storage, developers of solar projects have already started bundling battery storage with solar; the number of power purchase agreements for solar plus storage increased from **4 in 2017 to 16 in 2018**. With respect to flexible demand, it has the long-term capabilities to mitigate both curtailment and declining market values of wind and solar in high-penetration scenarios. An **RMI modeled analysis of ERCOT in 2050** found that flexible demand could increase wind and solar values by 36% and reduce curtailment by 40%. That such integration options as energy storage and flexible demand can both reduce integration costs and increase generation value may contribute to interest in their usage.

Table 1 does not detail how plant integration options would be achieved, all of which would involve costs of their own, from the installation and operation of thermal systems for space heating (flexible demand) to the construction and operation of battery facilities (energy storage).[10] As such, while plant integration options may be effective at reducing integration costs, the benefits of their deployment do not necessarily outweigh their costs. Furthermore, it is not obvious which particular technologies will be the most efficient. What is clear is that if intermittent renewables are to continue to grow as a percentage of total generation, one (or likely many) of these options would be necessary to limit the costs they impose on the grid and support their profitability. The implication of Table 1 is that only energy storage and flexible demand options have the potential for reduction within several of the integration cost categories. For example, in the case of solar in a grid with a large proportion of natural gas combustion turbines, flexible supply would keep residual generation costs low, but costs from curtailment could still be prohibitive.

Table 1. Plant Integration Options: Descriptions and Likely Effects on Integration Costs

Power Plant Integration Cost Category**	Plant Integration Options* — Demand-Side Options: **Flexible Demand** *Shifting demand to align with intermittent generation; includes water heating, space heating and cooling, plud loads and EV charging*	**Demand Response** *Short-term reduction of electricity consumption in response to a sudden decrease in supply*	Supply-Side Options: **Flexible Supply** *Increasing the proportion of dispatchable generators with lower fixed costs (e.g., natural gas rather than coal or nuclear)*	**Energy Storage** *Storing electricity from periods of low to high prices; includes flywheels, batteries, pumped hydro, compressed air, thermal storage, and hydrogen*	**Transmission Build-Out** *Building transmission between areas with high-quality solar or wind resources and areas of high electricity demand*
Balancing Costs (€5/MWh)	**No Effect** Balancing costs relate to managing the unpredictable variation of generation	**Reduced** Balancing costs would decline as demand responds to unpredictable drops in supply	**Limited Effect** Only a small amount of flexible supply is needed to manage unpredictable variation	**Reduced** Particularly with short-duration storage options	**Limited Effect** Potential for local reductions in balancing costs in areas with limited flexibility
Transmission / Grid Costs (€15/MWh)	**Limited Effect** Potential for less local transmission needs if demand is better matched to supply	**Limited Effect** Potential for less local transmission needs if local demand response options exist	**Limited Effect** Potential for less local transmission needs if local supply is more flexible	**Limited Effect** Potential for less local transmission needs with increased local energy storage	**Increased** Building out transmission directly increases grid costs
Adequacy / Backup Costs (€7/MWh)	**Reduced** Less need for redundant capacity if more demand is made coincident wih supply	**Limited Effect** Demand response may substitute for a small number of peaker plants	**Limited Effect** Moderately reduced need for additional backup if supply mix is more flexible	**Reduced** Less need for redundant capacity if more energy can be stored until periods of low supply	**Limited Effect** Potential for local reductions in backup costs in areas with limited flexibility
Curtailment / Overproduction Costs (€22/MWh)	**Reduced** Less generation will be curtailed if more demand is made coincident with supply	**No Effect** Unless demand can absorb additional supply, demand response would not affect curtailment	**Limited Effect** If curtailment is caused by inflexible supply (e.g. nuclear), greater flexibility would reduce curtailment	**Reduced** Less generation will be curtailed if energy can be stored until periods of low supply	**Reduced** However, it depends on the extent of correlated genera-tion and loads in neighboring areas
Residual Generation Costs (€16/MWh)	**Reduced** With more demand coincident with supply, fewer baseload generators would be needed	**No Effect** Demand response would substitute for peaker plants, which operate with low capacity factors	**Reduced** With more flexible supply, there are reduced costs to operating at lower capacity	**Reduced** With more energy storage, fewer baseload generators would be needed	**Limited Effect** Potential for local reductions in residual generation costs in areas with limited flexibility

* These options may also affect the costs of managing electricity demand (e.g. due to a spike in consumption during a hot summer afternoon), but such costs are separate from plant integration costs.

** Approximate magnitude of long-term integration costs in 40% wind power scenario. From Figured 9 and 10 in Falko Ueckerdt, L. Hirth, G. Luderer, and O. Edenhofer (2013), "System LCOE: What Are the Costs of Variable Renewables?" *Energy* 63 (15 December): 61-75.

Conclusion

This brief considers different measures for comparing electricity-generating technologies. We find that measuring generation value, in addition to generation cost, becomes increasingly important as we shift toward greater reliance on intermittent resources. Measuring integration costs further allows us to understand the deterrents to increasing shares of intermittent renewables and indicates which integration options have the ability to help address those costs.

Notes

1 Note that this does not directly include such external costs as the social cost of carbon or other emissions if current policies do not fully account for them. External environmental costs are reflected in these measurements only through a higher cost of capital due to future regulatory risk.

2 This brief is limited to the electricity sector, and thus it does not include such technologies as rooftop solar PV that compete with retail, rather than wholesale, electricity prices.

3 Curtailment occurs when power production exceeds the local capacity of the grid to use the electricity. It could result from high generation, low demand, insufficient transmission to move the electricity to reach available demand, or inflexible generation (such as nuclear) that cannot respond to excess grid supply.

4 In addition to energy and capacity revenue, power plants may receive compensation for providing ancillary services, such as adjusting generation to balance supply and demand on the grid. Ancillary services typically represent a small proportion of **total electricity prices**.

5 EIA presents simplified LCOE and LACE formulas with "expected annual generation hours" in the denominator rather than using present value calculations. However, if changes to costs, values, or electricity production are expected over time, discounting cash flows and electricity generation to their present values is a preferable method.

6 See note 3 on curtailment.

7 Although the individual and system perspectives take different approaches, both methods yield the **same optimal value** for the amount of intermittent renewables on the grid.

8 EIA projects an increase in the penetration of solar from 3.6 % in 2021 to 11 % in 2040, so it is not entirely clear why the range in values (LACE) does not decline over this period. Potential reasons include the growth in flexible demand and energy storage, as well as rising natural gas prices and strengthening state RPS and climate policies (as in California). However, more research is needed to fully explain the differences between solar-weighted wholesale electricity prices and LACE calculations.

9 The paper uses a reduced-form analysis, so it is not possible to attribute shares of the system price increases to generation costs and integration costs. However, since the system price increases are significantly greater than the difference between nonrenewable and renewable generation costs, the authors conclude that integration costs are a likely factor.

10 Note that a technological or market change could affect multiple options. For example, a programmable thermostat responding to real-time prices could accomplish both demand response and flexible demand.

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