Beyond LCOE: A Systems-Oriented Perspective for Evaluating Electricity Decarbonization Pathways

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CLEAN AIR TASK FORCE

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Executive Summary

Levelized Cost of Electricity (LCOE) is a widely used standardized metric to assess electricity generation project costs per expected generation output. Often used to compare technology costs, LCOE has become a ubiquitous metric used in electricity industry literature, cost forecasts, project business cases, and policy making.

The LCOE metric is popular in part due to its simplicity and standardization and has been used widely to display LCOE declines of solar and wind. LCOE is calculated by summing the discounted project cost, primarily capital and operating expenditures, and dividing those costs by the discounted expected electricity generation over the life of the project.

While LCOE is a good metric to track historical technology cost evolution, it is not an appropriate tool to use in the context of long-term planning and policymaking for deep decarbonization. Indeed, clean firm technologies[2] have been shown to significantly reduce the cost of decarbonization despite having a higher LCOE than wind and solar due to their offsetting impacts on reducing infrastructure and costs.

LCOE Shortfalls

Despite its popularity, LCOE has significant limitations that make it insufficient and unsuitable as the sole metric for policymaking, decision making, and comparing the value of different electricity generation technologies. The use of LCOE is especially fraught in the context of long-term system and deep decarbonization planning, clean energy technology value assessment, and supplying the recent surge in load growth forecasts.

LCOE does not consider a project's value to the system because of key shortfalls:

- LCOE does not consider a system's needs,
- LCOE does not consider the technology's generation profile,
- LCOE does not consider the technology's generation profile or generation characteristics such as dispatchability and inertia,
- LCOE often does not account for the full electricity system cost necessary to deploy a generator at a large scale, such as the transmission and distribution infrastructure necessary to deliver power to consumers.

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1 Doctoral student at the Energy and Resources Group at University of California, Berkeley

2 Clean firm power technologies refer to technologies that can generate electricity on-demand, regardless of the weather or time of day, with minimal emissions. Clean firm power technologies can achieve very high-capacity factor, if required. Technologies including, but not limited to, nuclear fission, fusion, geothermal (incl. superhot rock geothermal), combustion with carbon capture and storage, zero-carbon fuel combustion are considered to be clean firm.

In addition, the use of LCOE suffers from other shortfalls prevalent in analysis methods that are purely based on cost analysis:

- LCOE does not consider non-electricity infrastructure tradeoffs (e.g. land use, health effects, local economic benefits, and etc.),
- LCOE is highly sensitive to financial assumptions that differ between investors and technologies, and
- LCOE often does not consider impacts of uncertainty or volatility of input costs that may arise from supply chain strains or other world events (e.g. critical mineral prices or conflict related commodity price increases).

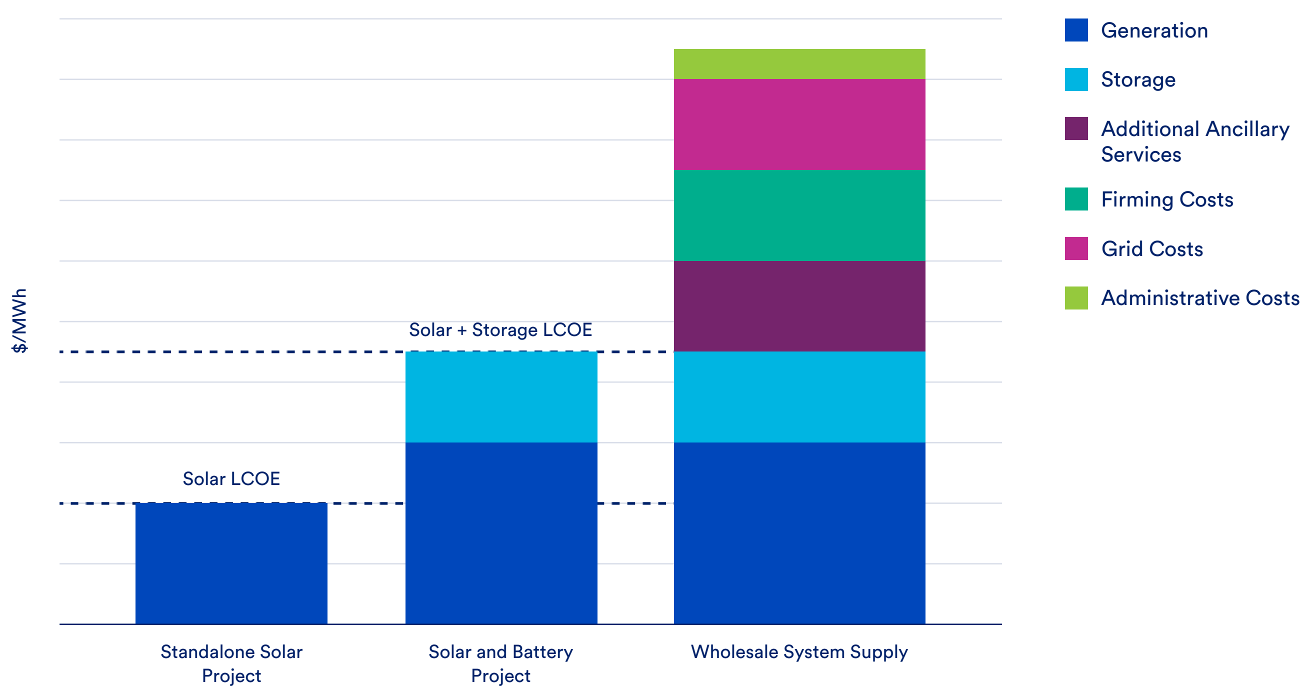
Customer electricity costs are not merely summations of individual project LCOEs across the system, but are more complex determinations based on total system costs to ensure a reliable and resilient power system. Therefore, it is critical to understand these limitations and their implications in policy conversations around consumer electricity costs. Total electricity system costs include costs related to generation and storage, transmission, and distribution infrastructure and administrative and policy related costs.

For instance, only a third of the customer costs in the UK are directly attributed to electricity generation and storage while the remainder comes from various other system and administrative costs. In California, this figure is even lower at roughly 25% due to significant transmission and wildfire related expenses. It is misleading to use LCOEs as a proxy for the potential consumer cost impacts of energy technologies and systems. Despite this, generation choices can impact numerous system costs, especially at scale.

Figure 1 below provides an illustrative example comparing the stand alone LCOE of two projects, in this case solar (left) and solar plus storage (middle), to system cost perspective (right). Importantly, it is worth noting that choices of generation not only impact the generation cost portion, but also the firming, ancillary, and grid costs necessary.

Figure 1: Illustrative breakdown of costs from several perspectives

(Left) The levelized costs of supplying an annual amount of energy using solar, equal to solar's LCOE
(Middle) The costs of supplying an hourly amount of energy using solar and storage
(Right) All costs that add up to customer costs



Solely Using LCOE is Not Appropriate for Long-Term Planning

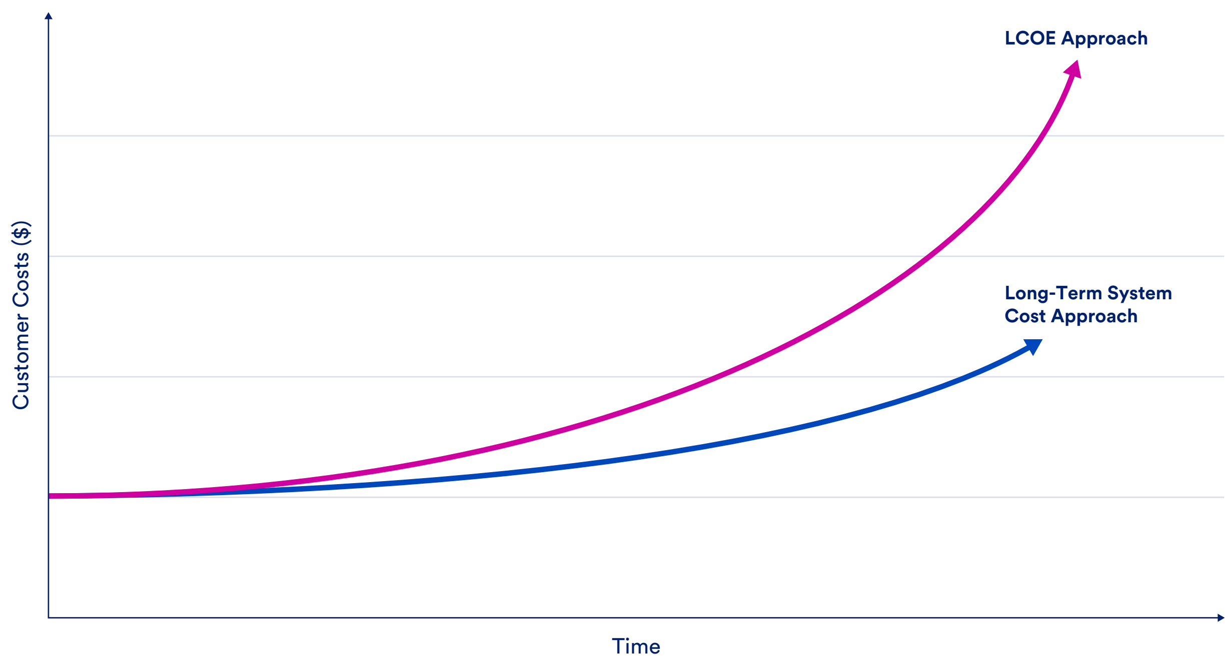
Therefore, it is unsuitable to solely use LCOE for planning, policymaking, and decision in the contexts where system reliability is becoming strained or for deep decarbonization.[3] LCOE might be useful in a narrow context where a system already has sufficient firm capacity to meet reliability needs, has low amounts of weather-based renewable resources, and does not suffer from significant transmission congestion. However, when renewables approach higher levels of penetration, systems face rising reliability needs, or other local context might constrain resource decisions, the LCOE of a stand-alone resource becomes less relevant as system needs evolve and additional costs and solutions are necessary to integrate projects into the system.

Take a recent example in Canada, where the Ontario government recently approved the development of nuclear small modular reactors (SMRs). Despite the SMRs having a higher project-level LCOE, the independent system operator system analysis indicated that they were cost effective when compared to the equivalent amount of wind, solar, storage, and transmission upgrade costs.

In the context of deep decarbonization, making decisions solely based on LCOE will lead to a higher cost system than necessary (Figure 2). Comprehensive *system* studies often indicate that the inclusion of a diverse set of transmission, clean firm,[4] and demand-response technologies can significantly reduce customer costs while ensuring a reliable, decarbonized grid, despite some resources having a high LCOE.

Figure 2: Illustrative figure displaying customer cost evolution under two approaches

(1) a short-sighted approach where decisions are made solely on LCOE (magenta)
(2) an approach based on long-term system cost (blue)



3 Emblemsvåg, J. Rethinking the "Levelized Cost of Energy": A critical review and evaluation of the concept. Energy Research & Social Science (2025).

4 Clean firm power technologies refer to technologies that can generate electricity on-demand, regardless of the weather or time of day, with minimal emissions. Clean firm power technologies can achieve very high-capacity factor, if required. Technologies including, but not limited to, nuclear fission, fusion, geothermal (incl. superhot rock geothermal), combustion with carbon capture and storage, zero-carbon fuel combustion are considered to be clean firm.

Put another way, some technologies can yield a significant reduction in system costs even if their LCOEs are higher than the lowest-LCOE resource available. This underscores the risk of relying on LCOE as the primary metric in policymaking, reporting, and decision-making processes that have long-term impacts, whether it be for explicit resource procurements or how the narrative of technology cost comparisons permeate into influencing the level of support from policy.

While LCOE's limitations as a metric for electricity planning are significant, it has influenced public perception, policymaking, and media discussion around clean energy technologies.[5] It is likely that LCOE's simplicity has incorrectly anchored it as a commonly used metric among many stakeholders. For example, LCOEs of renewables and clean firm resources, such as next-generation geothermal and nuclear, are often quoted to compare technologies' value without any context of how they may impact system costs, maintain reliability, and lower barriers to infrastructure deployment.

Alternatives to LCOE

As the electricity system rapidly evolves and the need for more sophisticated decarbonization planning becomes clearer, it is increasingly evident that the sole use of the LCOE metric is insufficient. New metrics, such as "Value-Adjusted LCOE," "Levelized Avoided Cost of Electricity," "Levelized Full System Costs of Electricity," and the adding "firming" costs to LCOE metrics, have attempted to address some shortfalls of the most basic version of the LCOE metric. Others have proposed comparing resources based on the cost to revenue ratio or simply comparing technologies that operate similarly. These approaches are notable improvements, but simple metrics still often fall short of the insights provided by long-term comprehensive systems analyses.

Instead of using LCOE in isolation, decarbonization policy, industry strategy, and public debate should rely on jurisdiction-specific system-level analysis where possible. Such analysis would consider all the system costs required to ensure a reliable and resilient power system and would capture infrastructure cost tradeoffs over long- and uncertain-time horizons. Such analyses would:

- Consider all technology solutions and system costs required to meet the needs of a system and ensure a reliable and resilient power system, including balancing costs, grid infrastructure costs, resource adequacy costs, and non-power constraints,
- Model temporal supply and demand to simulate the daily, weekly, and seasonal variability of generation of weather-dependent technologies,
- Model spatial supply and demand constraints between zones by representing the transmission system,
- Properly reflect the complex infrastructure cost tradeoffs over long and short-term horizons and,
- Account for climate, policy, weather, and economic uncertainties via scenarios and sensitivities.

While these studies are complex, difficult to execute, and also require significant review to ensure inputs are adequate, it is fortunate that many studies already exist in academic and industry literature. These studies cover many regions and can often readily be found online.[6] Using such studies will ensure that policymakers, regulators, utilities, and other stakeholders can make informed decisions that effectively support decarbonization goals while optimizing overall system reliability and minimizing customer costs.

5 Nuclear Power Still Doesn't Make Much Sense, New York Times, 2022. Carbon capture will probably make electricity more expensive, The Verge, 2023. 'No miracles needed': Prof Mark Jacobson on how wind, sun and water can power the world, The Guardian, 2023. The cheapest reliable energy system to meet Australia's climate targets? Solar and wind, no question, The Guardian, 2023.

6 A few examples include: Net-Zero America, Princeton University, 2024. Carbon-Free Europe Annual Decarbonization Perspective 2024, Evolved Energy Research, 2024. Least Cost Carbon Reduction Policies in PJM, Ethree, 2020. Net-Zero New England: Ensuring Electric Reliability in a Low-Carbon Future, Ethree, 2020. SB 100 Joint Agency Report, California Air Resources Board, 2021. Understanding the Costs of Integrating Energy Resources in PJM: Analyzing Full-Cycle Levelized Costs of Electricity, EPSA, 2024.

SECTION 1

Introduction

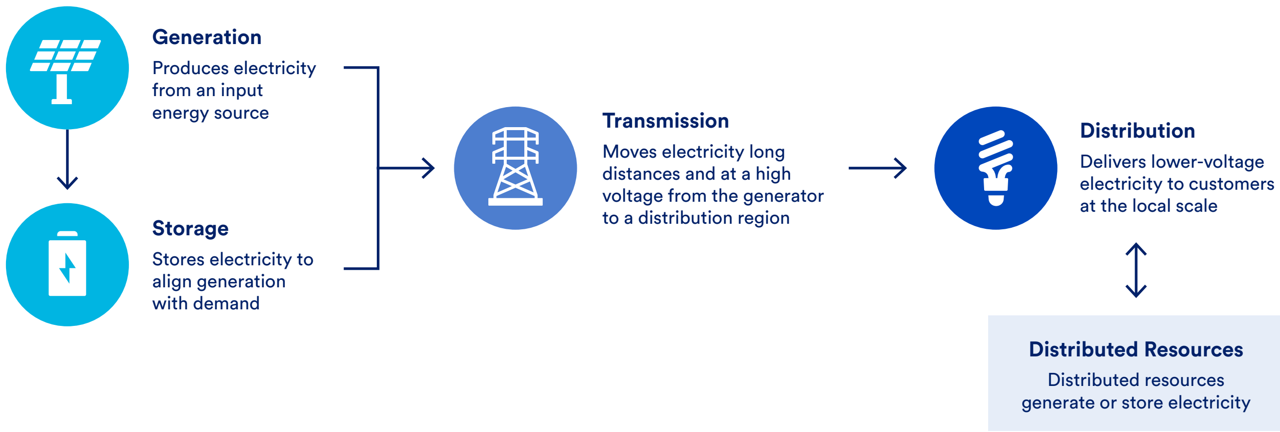
The concept of Levelized Cost of Electricity (LCOE) emerged in the mid-20th century as the energy sector sought standardized methods to evaluate and compare the project costs of different electricity generation technologies per unit of electricity generated. LCOE's goal was to characterize the sum of a project cost, primarily capital and operating expenditures, based on a set of historical, forecasted, and assumed inputs, and divide those costs by the expected electricity generation, regardless of the variability or uncertainty of the generation output. Simply put, LCOE assesses the project costs (or revenue necessary) for a single power plant.

Customer costs, however, are not the summation of individual project LCOEs across the electricity system. In contrast to LCOE, customers' electricity costs are based on the sum of system costs necessary to deliver reliable and low-emission electricity. These system costs fall into three main categories: generation and storage, transmission, and distribution (Figure 3). Customers pay for these costs either through regulated cost-recovery mechanisms, market electricity prices, or different mechanisms applied to different types of infrastructure. For additional power system basics, see the Annex at the end of the document.

Comprehensive power system planning seeks to minimize total system costs and customer costs while ensuring reliable and low-emission electricity, optimizing trade-offs of investments in various categories over long-time horizons and under a variety of scenarios and sensitivities. The three objectives of affordability, reliability, and low-emission make up the three pillars of what is often referred to as the "energy trilemma," a framework that decisionmakers use to balance trade-offs in energy policies and integrated planning processes.

Despite the customer costs being more directly reflected by system costs, LCOE's popularity gained significant attention in the climate and clean energy developments of the 2000s and 2010s as a simple means for comparing clean electricity generation technology project costs against one another, forecasting or measuring technology cost progress, and comparing clean electricity costs against emission emitting alternatives. As an example, Lazard's annual LCOE report is often cited in media reports, policy briefings, and clean-energy related reports. Forecasts for technology costs are also often presented in the form of future forecasted LCOE.

Figure 3: Components of a power system. Power systems are typically broken into three distinct components: generation and storage, transmission, and distribution



The rise of LCOE's popularity to evaluate technology competitiveness also coincided with a period of stagnant load growth in the United States and Europe. Without significant load growth and an existing electricity system primarily making up dispatchable or baseload capacity, the need to consider various system needs and costs, such as additional transmission or firm capacity needs was relatively low during this time compared to the load growth prior to the 1990s and today. As a result, the use of LCOE as a near-term planning metric was valid in some circumstances, which further anchored it as a go-to metric for many stakeholders.

Over time, however, the limitations of LCOE for complex long-term electricity system planning have become more apparent as load growth has rebounded, aging generation plants are forecasted to close, and as deep decarbonization scenarios that require complex analysis are pursued. As we discuss in this report, LCOE falls short in many ways. These limits have spurred efforts by academics and industry analysts to develop complementary metrics, such as "Value-Adjusted LCOE," "Levelized Avoided Cost of Electricity," "Levelized Full System Costs of Electricity," and adding "firming" costs to LCOE metrics. While these metrics are an improvement, simple metrics often fall well short of long-term comprehensive systems analysis required to adequately assess the best solutions for electricity systems. As such, using these new metrics still risks an incomplete understanding of tradeoffs of different solutions that could either result in either shortsighted resource procurement decisions or policymaking prevents or provides insufficient support for other necessary technologies.

In summary, LCOE was developed out of necessity to compare electricity generation technologies on a common generation output basis and its simplicity and versatility made it a cornerstone of energy planning and policy. But evolving electricity system context and the need for complex decarbonization planning has revealed its limitations and the need to move beyond the use of LCOE as the primary metric used in policymaking, reporting, and decision making.

SECTION 2

Levelized Cost of Electricity (LCOE)

Basics of LCOE

LCOE represents the average cost per unit of energy produced (e.g., $/MWh) for a particular electricity generating technology — that is, it takes net present value (NPV) of the capital and operational costs of the technology and divides them by the NPV of expected energy production over the technology's lifespan. Put another way, it is the average energy revenue that would be required for an investor when using an investor's cost of capital in the NPV calculation.

The equation for LCOE can be approximated as follows:

$$\text{LCOE} = \text{NPV}\left[\frac{\text{lifetime costs (\$)}}{\text{lifetime generation (MWh)}}\right]$$

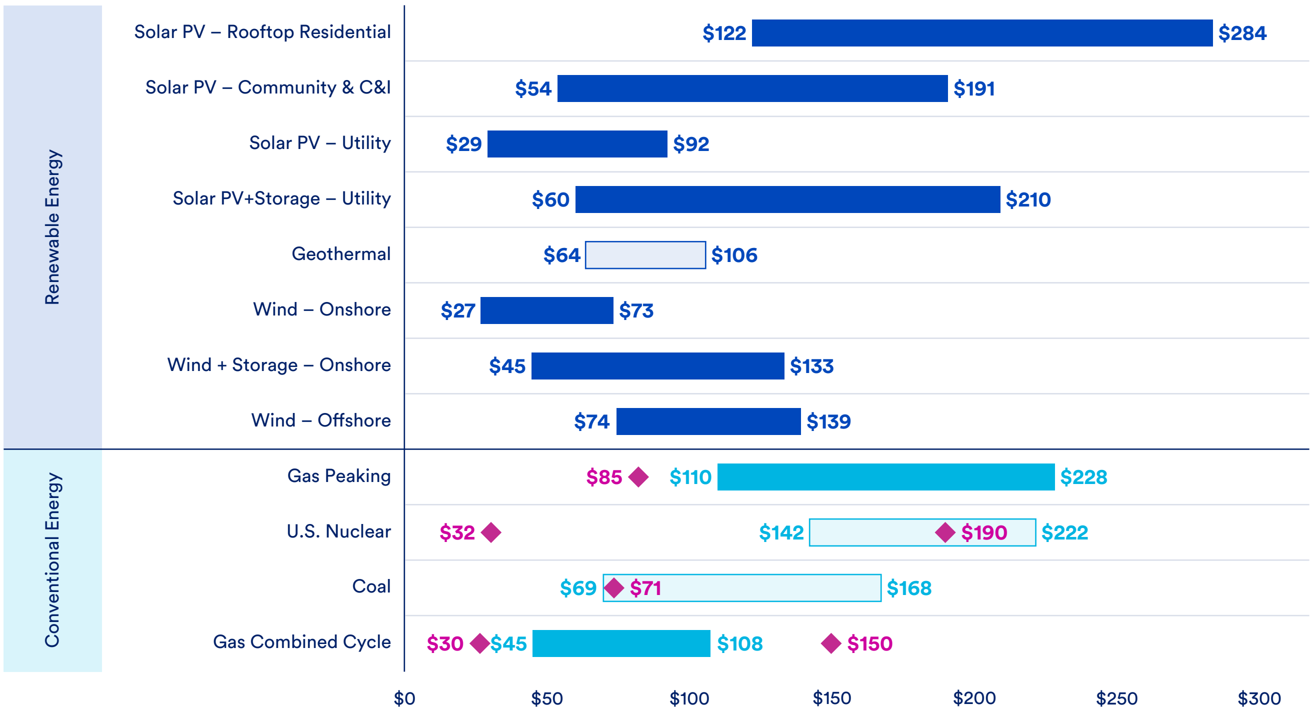
The LCOE of technologies has changed dramatically over time for different technologies and regions for several reasons. For natural gas, the shale gas boom in the U.S. drastically reduced the cost of natural gas generation and thus its LCOE. In contrast, Europe continues to experience high gas prices, especially after the invasion of Ukraine. For renewable energy resources such as wind and solar, manufacturing innovation and installation efficiencies have resulted in rapid cost declines. As of 2024, Lazard estimates the LCOE of onshore wind and utility-scale solar generation to be the lowest in the United States and parts of Europe, while residential solar PV, peaking gas capacity, and renewables paired with storage have higher values (Figure 4). LCOE can vary dramatically by region due to variations in fuel costs, labour costs, and expected generation (e.g. the quality and quantity of wind or sun in different areas).

Short-Falls of Existing LCOE Methods

While LCOE enables a quick and seemingly straightforward comparison of costs between different electricity generating technologies, there are many shortfalls associated with this metric and its use to inform clean energy policymaking and strategy.

Figure 4: LCOE of various generation technologies

Source: [Lazard's Levelized Cost of Energy Analysis – Version 17.0]



The primary shortfall of LCOE is that it often only includes direct costs of a project (such as capital or operational costs); it does not assess the value of a project to the system nor the many other associated costs that are required to have a reliable, affordable, and sustainable electricity system. Because LCOE excludes important nuances, it misrepresents not only the competitiveness of a single project, but also a technology's role at scale within an electricity system.

LCOE does not consider a project's value to the system because of key shortfalls:

- LCOE does not consider a system's needs,
- LCOE does not consider the technology's generation profile or generation characteristics such as dispatchability and inertia,
- LCOE often does not account for the full electricity system cost necessary to deploy a generator at a large scale, such as the transmission and distribution infrastructure necessary to deliver power to consumers.

In addition, the use of LCOE suffers from other shortfalls prevalent in other analysis methods that are purely based on cost analysis:

- LCOE does not consider non-electricity infrastructure tradeoffs (e.g. land use, health effects, local economic benefits, and etc.),
- LCOE is highly sensitive to financial assumptions that differ between investors and technologies, and
- LCOE often does not consider impacts of uncertainty or volatility of input costs that may arise from supply chain strains or other world events (e.g. critical mineral prices or conflict related commodity price increases).

LCOE provides no information regarding the system's needs

The evaluation of a new electricity project is based on the cost and value of the project and alternative options. While the cost of projects is relatively straightforward to estimate, the value of projects requires a system assessment of needs, which often requires complex modeling analysis.

Electricity systems are complex and are made up of many long-lasting infrastructure projects (Figure 3). When new projects are proposed, they are within the context of an existing system and that system's needs. In addition, the future of electricity systems is subject to much uncertainty that has significant impacts on the valuation of projects. Examples of uncertainty include the future costs of fuel, the rate of transmission development, the amount of load growth, and so on.

For example, LCOE does not assess the existing penetration of VREs or the need for reliable power solutions and thus ignores the economic value a new project would add a specific system. If a system already has more than enough solar generation during the day to meet demand, more solar might not be the solution unless storage is added (which adds costs to the simple solar LCOE). If a system's peak load is growing, this may require a combination of firm, weather-based, storage, and demand response solutions to achieve the lowest cost system.

The use of LCOE provides no context regarding the needs of the system. New metrics, such as "Value-Adjusted LCOE," "Levelized Avoided Cost of Electricity," "Levelized Full System Costs of Electricity," and adding "firming" costs to LCOE metrics, have attempted to address some shortfalls of the most basic version of the LCOE metric. Others have proposed comparing resources based on the cost to revenue ratio. While these metrics are an improvement, simple metrics often fall well short of long-term comprehensive systems analysis and, even if they are based on comprehensive system analysis, they can conceal tradeoffs in a singular metric that lead to incomplete understanding of tradeoffs of different solutions (e.g. transmission buildout needs).

To assess the system needs, jurisdiction-specific system-level analysis is required. Such analysis can come in several forms, but generally would:

- Estimate the shortfalls necessary to ensure a reliable and resilient power system given a set of future input scenarios (e.g. load) while considering other potential jurisdictional constraints (e.g. build rate limitations),
- Model temporal supply and demand to simulate the daily, weekly, and seasonal variability of generation of weather-dependent technologies,
- Model spatial supply and demand constraints between zones by representing the transmission system,
- Properly reflect the complex infrastructure cost tradeoffs over long and short-term horizons and,
- Account for climate, weather, policy, and economic uncertainties via scenarios and sensitivities.

To demonstrate the value and shortfalls of LCOE as a metric, we evaluate LCOE's usefulness under a variety of scenarios in Annex B. These scenarios are designed to reflect a hypothetical evolving power system, one that begins as highly dependent on dispatchable, fossil-fueled resources to a decarbonized system that must support an electrified economy. Table 1 provides a summary of the scenarios, and results of each evaluation, which are outlined in more detail in the following subsections.

LCOE does not consider the technology's generation profile or generation characteristics

LCOE is often used to compare costs between technologies normalized by generation, regardless of when the electricity is generated or whether its generation can be controlled by a system operator. Unless technologies are nearly identical in their potential generation output, the sole use of LCOE is problematic for assessing whether a technology can lower overall system and customer costs relative to alternative technologies.

Historically, most generating resources — such as fossil-fired generators, nuclear, and most hydroelectric generators with reservoirs — could control their generation output and had degrees of dispatchability that varied by technology and had inertia. As a result, maintaining adequate dispatchability and inertia was not a major concern for grid operators, who had sufficient confidence in their ability to manage resources and meet demand under normal conditions.

Table 1: Outline and results of each power system scenario

LCOE can be a useful metric primarily in scenarios with low renewable penetration and no significant demand for peak capacity, flexibility, or transmission. However, in cases where the system requires these elements or already has a high penetration of variable renewable energy (VRE), it becomes essential to employ additional metrics to assess the overall system value and total costs of investments.

Situation	VRE Penetration	Firm Capacity Retirement	Peak Load Growth	LCOE Appropriateness
1. No system need for flexibility or firm capacity (e.g. after 2008 in Europe)	Low	Low	Low	LCOE may be appropriate if all relevant costs are accounted for, but still likely falls short due ignoring other trade-offs.
2. Rapidly growing VRE penetration, but no new peak capacity needs (e.g. California from 2010s to today)	Moderate	Low	Low	LCOE is insufficient, as it fails to reflect whether a resources can provide for system needs of flexibility and dispatchability (or does not account for the costs associated with managing intermittency).
3. Need for additional peak capacity (e.g. most of the US today faces significant load growth)	High or Low	High	High	LCOE is insufficient; it is essential to consider a solutions' abilities to serve peak demand and its associated costs.
4. Long-term economy-wide decarbonization	High	High	High	LCOE is insufficient, need to account for increased need for peak capacity, dispatchability, inertia, T&D infrastructure, and other costs. LCOE also does not consider other potential infrastructure challenges relevant for deep decarbonization.

Variable renewable energy (VRE) technologies, such as wind and solar, present different characteristics that are not captured by LCOE. These technologies can offer a lower LCOE compared to many other traditional emitting and clean firm technologies, such as nuclear, geothermal, and gas with high levels of carbon capture. Yet, VRE output is weather-dependent and variable over days, weeks, and seasons. This variability may not be of concern when the amount of VRE is low or moderate. However, weather-based variability can lead to mismatches between electricity generation and demand without additional infrastructure, such as storage (Figure 5). This may also result in curtailment (i.e. waste) of generation during times of excess supply and low demand and insufficient supply during peak demand periods without sufficient storage or transmission (Figure 6). These challenges can be solved for with storage and additional transmission, but those solutions add cost that are not captured in LCOE metrics.

Figure 5: Declining resource adequacy value for a representative variable renewable resource

As system penetration of the resource increases, net peak shifts away from hours when the resource is generating, making the resource adequacy value of additional capacity of that resource less valuable.

Source: https://doi.org/10.1016/j.renene.2023.02.023

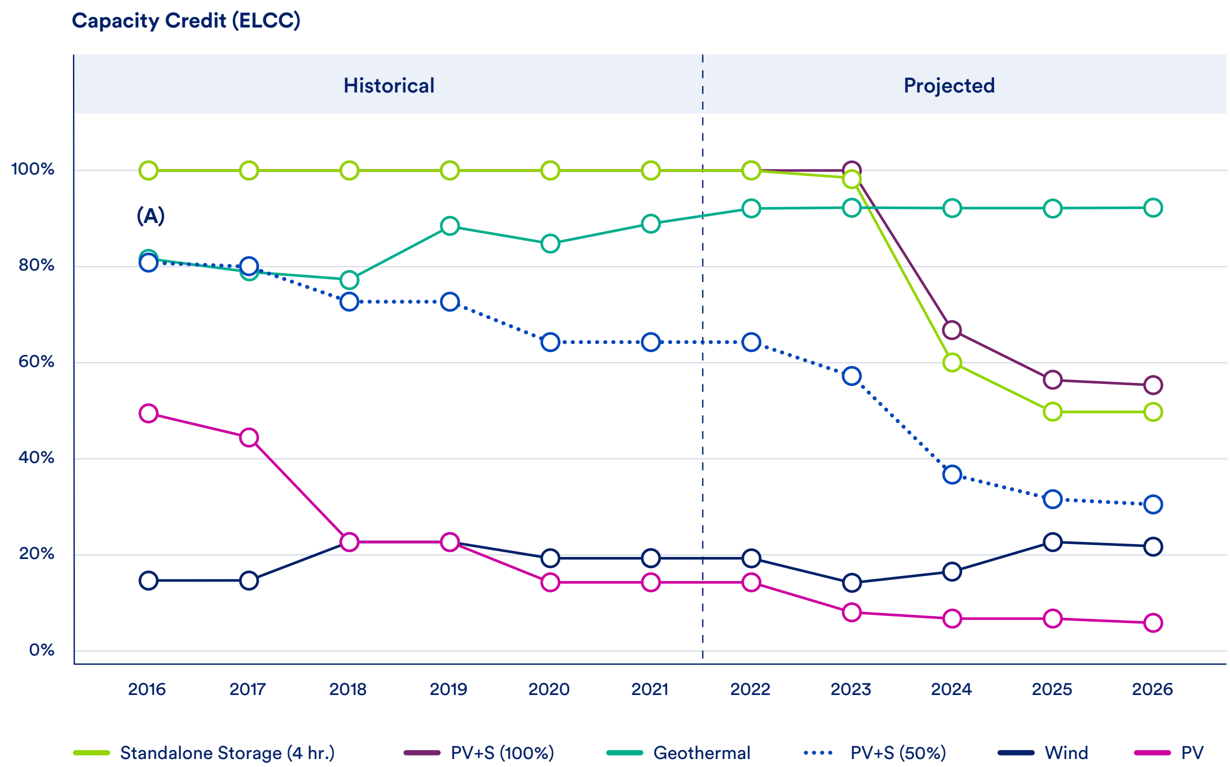
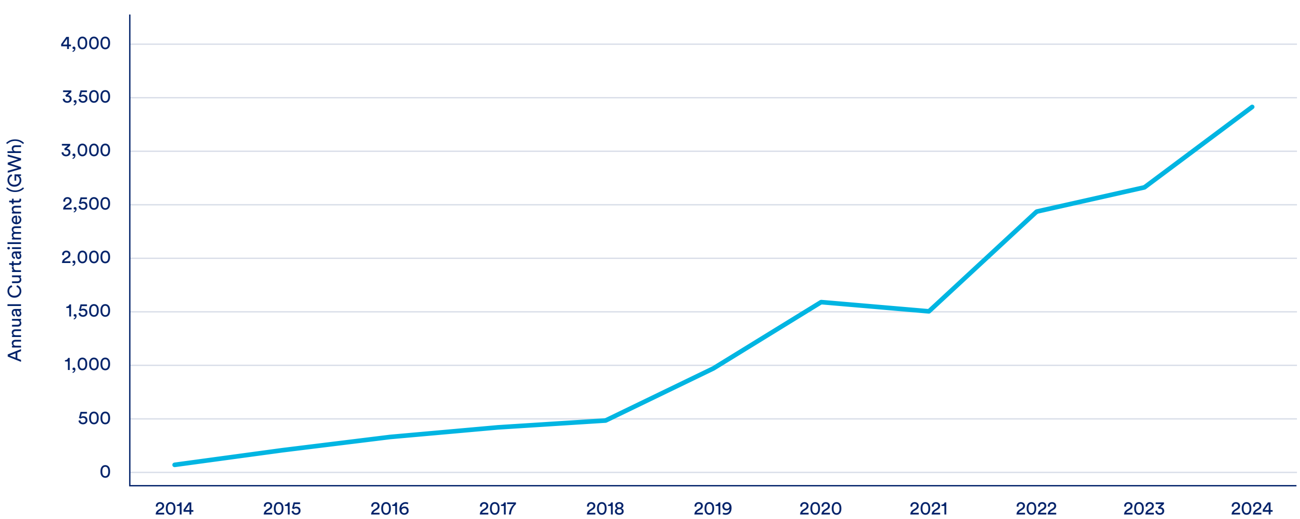


Figure 6: Annual curtailment in California

Based on data from CAISO.



LCOE also does not consider technology characteristics such as dispatchability, which describes how controllable the generation is (i.e. dispatchability), or how it impacts system reliability and resiliency (e.g. inertia). Dispatchability refers to a generator's ability to produce electricity when called upon, which is vital for balancing the grid's fluctuating supply and demand and maintaining system stability and reliability (e.g. frequency and voltage levels).[7,8] In addition, generating technologies have unique characteristics that can aid with system resiliency. As an example, technologies that have rotating generators (e.g. steam, combustion, or water turbines) have inertia, which is the kinetic energy stored in rotating masses, that is important for maintaining a reliable power system and providing spinning reserves.[9] These include nuclear, geothermal, and fuel combustion technologies. Another resiliency characteristic is black start capability, which refers to the ability of generation to restart parts of the power system to recover from a blackout. Factors like extreme weather events, will also increasingly threaten the dependability of various technologies, further complicating the task of maintaining a stable and reliable grid.

A partial remedy this shortfall is to compare LCOEs only for similar types of generation technologies within specific regions. As an example, EIA separates LCOE calculations by “dispatachable,” “resource-constrained technologies,” and “capacity resource technologies.[10]” Another approach is adding the costs related to additional infrastructure that helps adjust the generation output or diversify its generation profiles across regions. This includes, but is not limited to, transmission, storage, and demand response technologies.

LCOE does not account for the full system cost for integrating a technology at scale

Because LCOE measures the cost to produce a MWh of electricity for an isolated, discrete generation facility, it does not capture the total system costs associated with large-scale deployment of a technology or the system cost trade-offs associated with integrating various technologies into the grid.

As discussed above, the generation profile of VREs are variable over daily, weekly, and seasonal timescales and subject to weather storms that can impact generation output. To address these challenges, systems can diversify solutions, investing in those that can better align supply and demand conditions throughout the year. Battery storage has been shown to be cost effective in many jurisdictions for balancing daily fluctuations and imbalances of VRE supply and demand. Long-duration storage also has value, but would require dramatic cost declines beyond forecasted declines to cost-effectively balance longer timeframes of variability (e.g. seasonal). Moreover, additional transmission between congested zones can reduce costs by delivering low cost energy to demand and increasing VRE generation profile diversity from resources across regions.[11,12] To ensure the lowest cost decarbonized system, transmission will need to be planned in such a way that it maximizes the utilization of the transmission to reduce customer costs, whether it is transporting distant VRE to demand or citing clean firm generation that fully utilize transmission capacity in all hours of the day. Meanwhile, clean firm technologies such as nuclear and geothermal can provide reliability, no seasonal variability, and reduce the amount of infrastructure needed with their flexible siting and low transmission needs.

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7 Note that “dispatchable” resources consider both resources that prefer to constantly at full capacity, otherwise known as “baseload” (e.g. nuclear), and resources that fluctuate their output based on system needs (e.g. gas peakers). While their operating preferences will differ based on a variety of other cost and system characteristics, it is their ability to control their output that makes them dispatchable.

8 Note that all generating technologies have some uncertainty due to outage risks. Natural gas resources may fail to generate due to lack of natural gas supply, nuclear resources may fail to generate due to high water inlet temperatures.

9 When there's an imbalance between supply and demand, the inertia in the system resists the change in frequency. For example, if a large power plant fails, the stored energy in the system can temporarily make up for the lost power.

10 EIA, Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2023 (March, 2023), https://www.eia.gov/outlooks/aeo/assumptions/pdf/elec_cost_perf.pdf

11 https://www.brattle.com/wp-content/uploads/2021/10/Transmission-Investment-Needs-and-Challenges.pdf

12 Project-specific LCOE usually includes grid connection costs. These costs, which are shouldered by the investor, include the cost of spur lines (connecting the generator to the transmission grid), transmission substation upgrades, and upgrades to the surrounding network.

All these strategies come with system costs tradeoffs that are not reflected in a stand-alone resource's LCOE. These additional system costs are not directly borne by investors of any one project; rather, they are incurred at the system level and ultimately passed on to consumers. Overall, studies show that a portfolio of technologies optimized to meet the needs of a system have the lowest-cost outcome compared to more constrained technology portfolios (Figure 7).

LCOE does not include non-power tradeoffs

LCOE calculations primarily focus on the financial aspects of a standalone project, ignoring other tradeoffs that may be relevant. For example, LCOE does not account for the environmental, economic, and social impact of various technologies, ranging from the land-use impacts to the global impacts of a technology's supply chain, which can vary significantly by technology choice (Figure 8).

Ground-mounted solar and wind technologies can be far less energy-dense than natural gas, nuclear, and geothermal technologies, requiring both more direct land use and greater infrastructure footprints from related infrastructure (e.g. transmission) that may

Figure 7: Modelled system generation and transmission cost in a system with only renewables and storage vs. a system with renewables, storage, and clean firm generation

Source: Adapted from Baik et al., 2021

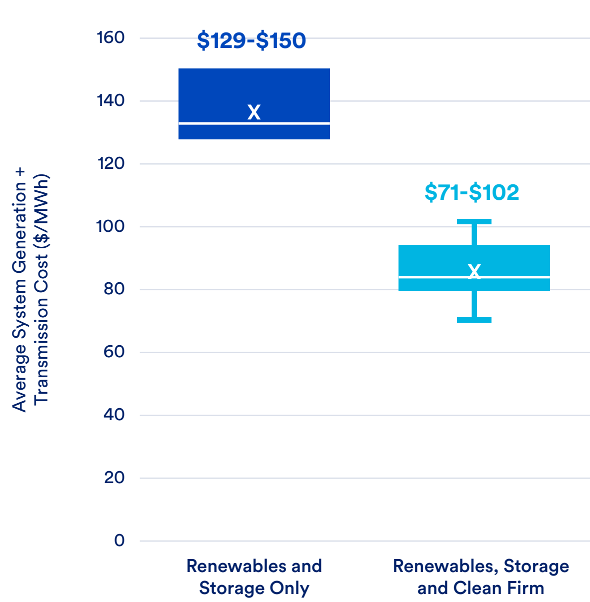


Figure 8

Source: US, Department of Energy. January, 2025.

	Clean?	Firm?	Low land use?	Low transmission buildout?	Concentrated local economic benefits?	Direct heat applications?
Nuclear	High	High	High	High	High	High
Geothermal	High	High	High	Medium	Medium	Medium
Hydropower	High	Medium	Low	Medium	High	Low
Renewables + LDES	High	Medium	Low	Low	Low	Low
Renewables: offshore	High	Medium	High	Low	Low	Low
Renewables: onshore	High	Low	Low	Low	Low	Low
Natural gas + CCS	Medium	High	Medium	High	Medium	Medium
Coal + CCS	Medium	High	Medium	High	High	Medium
Natural gas	Low	High	Medium	High	Medium	Medium
Coal	Low	High	Medium	High	High	Medium

High Medium Low

present siting and permitting challenges. However, such metrics are also highly variable and subject to change, as land use can be minimized via other land uses alongside the electricity infrastructure (e.g. dual-use solar) and transmission processes can be updated to increase deployment. Technologies also have different water use requirements, environmental contamination risks, and other impacts that may be relevant for a region.

Other important considerations for policymakers include jobs and local taxes. The jobs required to enable the buildout of new clean energy generation technologies (or their equipment manufacturing) has been a key selling point of the clean transition. This holds true for existing plant jobs, where existing communities often depend on existing plants for their employment and local tax benefits and require support or replacement plants. For example, a U.S. Department of Energy study found that replacing coal plants with nuclear plants could increase local jobs and tax revenue, while some studies point to a different in permanence of jobs between technologies.

LCOE is highly sensitive to financial assumptions and does not consider uncertainty of inputs

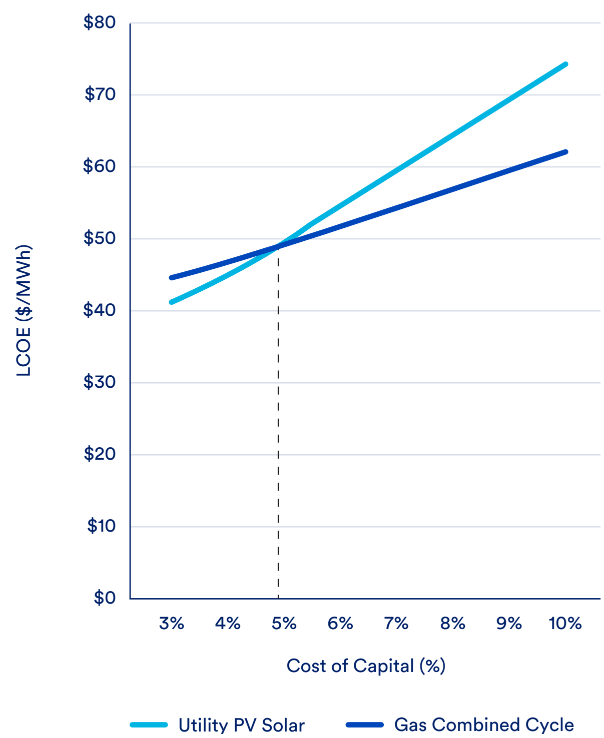
One of the main limitations of the LCOE metric is its sensitivity to various financial assumptions, which can vary significantly, particularly the discount rate.

The discount rate is used to estimate the present value of future cash flows necessary to pay off the investor, and any changes in this rate can significantly impact the LCOE calculations. This discount rate is often set by the cost of capital, which often equates to the sum of government-set risk-free rates and project-related premiums. When the discount rate is higher, future cash flows are given less value and, often, costs of capital are higher. This means that the costs incurred in the initial years of the project are weighted more heavily, making the LCOE appear higher. High cost of capital especially impact technologies that have high capital expenditures and/or low fuel expenditures (Figure 9).

This sensitivity to discount rates can lead to significant fluctuations in the LCOE. Yet, the choice of discount rate often depends on subjective factors, such as risk perception, investment preferences, and the risk-free rate set by macroeconomic conditions. Internationally, these conditions may vary substantially, especially in emerging and developing economies.[13] Over the last decade, very low risk-free interest rates in wealthy countries favored higher capital expenditure technologies, like wind, solar, and batteries. However, recent inflationary macroeconomic conditions have resulted in increased risk-free rates, increasing the cost of projects. Future risk-free rates are highly uncertain, and energy system planning studies must consider different future scenarios.

Figure 9: Example of how the cost of capital affects the LCOE of different technologies

At a lower cost of capital, utility scale PV solar has a lower LCOE. However, as cost of capital increases, the gas combined cycle generator becomes the less expensive option. Cost inputs are sourced from the National Renewable Energy Laboratory Annual Technology Baseline 2024, using a class IV solar resource and an F-Frame combined cycle gas turbine.



13 CATF, Evaluating the Weighted Average Cost of Capital (WACC) in the Power Sector for African Countries, 2024

SECTION 3

Policy Recommendations

LCOE remains a useful metric for tracking cost of a technology over time. However, using solely LCOE could prove misleading for long term policymaking, decision making and planning. So what is the alternative?

As the electricity system rapidly evolves and the need for more sophisticated decarbonization planning becomes clearer, it is increasingly evident that the sole use of the LCOE metric is insufficient. New metrics, such as "Value-Adjusted LCOE," "Levelized Avoided Cost of Electricity," "Levelized Full System Costs of Electricity," and the adding "firming" costs to LCOE metrics, have attempted to address some shortfalls of the most basic version of the LCOE metric. Others have proposed comparing resources based on the cost to revenue ratio or simply comparing technologies that operate similarly. These approaches are notable improvements, but simple metrics still often fall short of the insights provided by long-term comprehensive systems analyses.

Instead of using LCOE in isolation, decarbonization policy, industry strategy, and public debate should rely on jurisdiction-specific system-level analysis where possible. Such analysis would consider all the system costs required to ensure a reliable and resilient power system and would capture infrastructure cost tradeoffs over long- and uncertain-time horizons.

Such analyses would:

- Consider all technology solutions and system costs required to meet the needs of a system and ensure a reliable and resilient power system, including balancing costs, grid infrastructure costs, resource adequacy costs, and non-power constraints,
- Model temporal supply and demand to simulate the daily, weekly, and seasonal variability of generation of weather-dependent technologies,
- Model spatial supply and demand constraints between zones by representing the transmission system,
- Properly reflect the complex infrastructure cost tradeoffs over long and short-term horizons and,
- Account for climate, policy, weather, and economic uncertainties via scenarios and sensitivities.

In the context of deep decarbonization, comprehensive system studies often indicate that the inclusion of a diverse set of transmission, storage, clean firm,[14] and demand-response technologies can significantly reduce customer costs while ensuring a reliable, decarbonized grid.

While these studies are complex, difficult to execute, and also require significant review to ensure inputs are adequate, it is fortunate that many studies already exist in academic and industry literature. These studies cover many regions and can often readily be found online.[15]

Using such studies will ensure that policymakers, regulators, utilities, and other stakeholders can make informed decisions that effectively support decarbonization goals while optimizing overall system reliability and minimizing customer costs.

14 Clean firm power technologies refer to technologies that can generate electricity on-demand, regardless of the weather or time of day, with minimal emissions. Clean firm power technologies can achieve very high-capacity factor, if required. Technologies including, but not limited to, nuclear fission, fusion, geothermal (incl. superhot rock geothermal), combustion with carbon capture and storage, zero-carbon fuel combustion are considered to be clean firm.

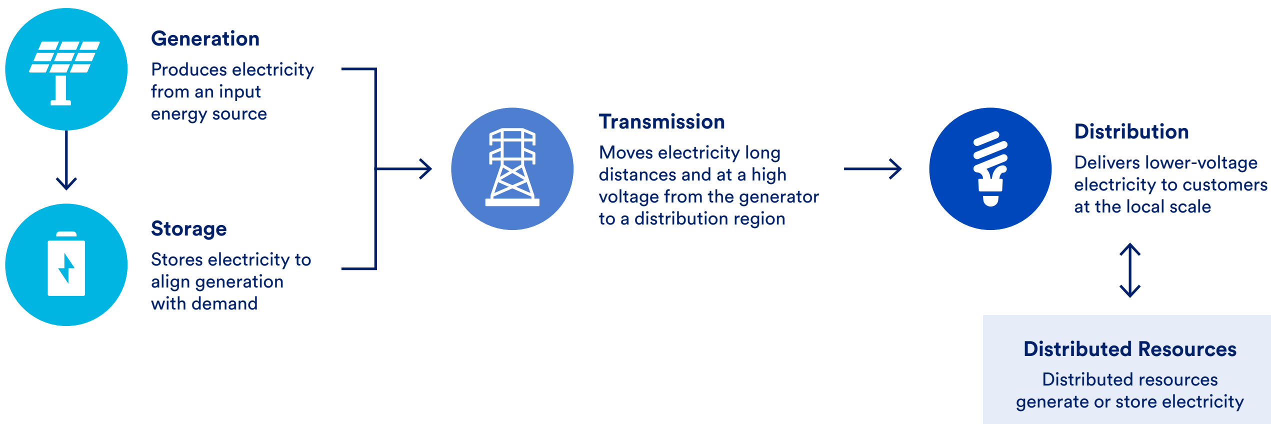
15 A few examples include: Net-Zero America, Princeton University, 2024. Carbon-Free Europe Annual Decarbonization Perspective 2024, Evolved Energy Research, 2024. Least Cost Carbon Reduction Policies in PJM, Ethree, 2020. Net-Zero New England: Ensuring Electric Reliability in a Low-Carbon Future, Ethree, 2020. SB 100 Joint Agency Report, California Air Resources Board, 2021. Understanding the Costs of Integrating Energy Resources in PJM: Analyzing Full-Cycle Levelized Costs of Electricity, EPSA, 2024.

ANNEX A

Power System Basics

Components of Power Systems

Power system infrastructure falls into three main categories: generation and storage, transmission, and distribution.



Generation and Storage

Electricity generation refers to the process of converting energy from various sources into electrical power. This often involves translating the mechanical energy of a spinning turbine into electrical energy. Traditionally, fossil fuels — like natural gas, oil, and coal — have been used to spin turbines, either being combusted directly in a turbine or burned to turn water into steam, which then spins a turbine. Other conventional sources include hydropower, which uses the kinetic energy of falling water to turn turbines as it flows from a higher to a lower elevation and nuclear, where chemical reactions in radioactive materials generate heat to produce steam for turbine movement. In the past two decades, solar and wind generation technologies have gained significant traction as low-emission alternatives, allowing for electricity production without direct CO_2 emissions. These technologies harness energy from the sun or wind and transform them into electricity. New technologies like geothermal energy, which utilizes heat from beneath the Earth's surface to produce steam for turbines, and nuclear fusion are also on the horizon, promising additional carbon-free generation options.

Storage refers to the process storing energy and delivering the power back to the grid or end-use. Historically, the dominant form of storage present in electricity systems were hydropower reservoirs, which stored the potential energy of water in a reservoir and converted it to electrical power via a turbine. In addition, pumped hydropower storage, which consumes power to pump water uphill into a storage reservoir and then runs that water through a turbine an generate electrical power, is also present in some regions. The challenge of balancing the supply from weather-dependent renewables with demand, and the lack of potential for expanding hydro reservoirs and pumped storage, has motivated the creation of new storage technologies, namely batteries and various forms of mechanical storage (e.g. compressed air). These technologies aim to store power during times when there is excess renewable energy generation and return it to the grid later, at an efficiency penalty.

Generating resources are often classified as "dispatchable" or "non-dispatchable." Dispatchable resources are those that can (barring scheduled or unexpected outages) controllably increase or decrease their output in response to the needs of the system (e.g., the amount of electricity demand that needs to be served). Examples of dispatchable resources include most fossil-fired generators, nuclear reactors, and some hydroelectric plants.

Non-dispatchable resources — sometimes also called "intermittent" or "variable renewable energy (VRE)" — are resources whose output is dependent on conditions unrelated to grid conditions, such as weather. Examples of non-dispatchable resources include solar and wind.

Dispatchability plays a crucial role in the electricity grid, as storing electricity is inherently challenging and costly compared to other energy sources like oil and gas. Historically, electricity storage was primarily achieved through hydroelectric power, where water was stored behind large dams to meet high demand. With the rapid decline in the cost of shorter-duration batteries, we are now seeing increased use of these technologies to balance daily supply and demand imbalances.

As non-dispatchable resources make up a larger portion of the electricity mix, system planners are placing greater emphasis on the need for seasonal or long-duration energy storage. These technologies allow for the management of extended periods — weeks or even months — of imbalanced VRE production relative to demand. Although many of these technologies are still in development, promising examples include hydrogen production and storage, compressed-air energy storage, and thermal energy storage.[16]

Transmission and Distribution

Both transmission and distribution move electricity between generator and the consumer. Transmission refers to the infrastructure that moves large amounts of power over long distances between a generation source and a local distributor. To minimize losses from moving power over such long distances, transmission lines operate at a much higher voltage than distribution lines. Distribution lines, on the other hand, carry electricity at a local level from a transmission substation to the final consumer. Since distribution networks are located much closer to population centres, homes, and businesses, they are operated at a lower voltage for safety reasons and to better match the electricity needs of those customers.

Three Needs of Power Systems

It is widely recognized[17,18] that power systems need to achieve the following objectives:

1. **Reliability:** the "provision of an adequate, secure, and stable flow of electricity as consumers may need it"[19]
2. **Affordability:** providing electricity to consumers at a reasonable cost to society
3. **Sustainability:** generating electricity in a manner that minimizes carbon emissions, air pollution, and other environmental harms

These objectives make up the three pillars of what is often referred to as the "energy trilemma," a framework that decisionmakers use to balance trade-offs in energy policies and integrated planning processes.[20]

16 https://www.lazard.com/media/42dnsswd/lazards-levelized-cost-of-storage-version-70-vf.pdf

17 https://commonslibrary.parliament.uk/research-briefings/cdp-2023-0074/

18 https://unstats.un.org/sdgs/report/2023/The-Sustainable-Development-Goals-Report-2023.pdf

19 https://www.ferc.gov/reliability-explainer

20 https://trilemma.worldenergy.org/reports/main/2023/World%20Energy%20Trilemma%20Index%202024.pdf
https://commonslibrary.parliament.uk/research-briefings/cdp-2023-0074/

Reliability

Achieving an acceptable level of electric reliability is comprised of two main components. *Operational reliability* refers to the grid's ability to withstand sudden changes and disturbances (e.g., increases in demand, generator outages, transmission line interruptions) that would otherwise lead to blackouts. *Resource adequacy* refers to the power system having enough physical generating capacity to supply the projected electric demand from consumers.

Electricity demand and supply conditions are changing moment-to-moment. Achieving operational reliability involves strategically scheduling generation resources to meet anticipated demand while also responding swiftly to sudden and unexpected fluctuations in supply and demand. This ensures that electricity production and consumption remain balanced, and that grid voltage and frequency stay within acceptable limits, allowing for smooth electricity flow and preventing potential damage to equipment, appliances, and devices. While all generation resources can help meet demand, only specific resources are equipped to provide short-term balancing of supply and demand, as well as maintain voltage and frequency — services often referred to as "ancillary services."

Resources that provide ancillary services possess certain key qualities: they have the flexibility to adjust their output quickly (within less than 30 minutes) and/or sufficient inertia — energy stored in large rotating generator turbines — that acts as a buffer, helping to maintain grid frequency stability during sudden shifts in generation or demand. Historically, when generation on the grid was predominantly large, spinning turbines, ancillary services were often taken for granted, representing a smaller portion of the overall value generators could provide to the grid. However, as renewable energy sources with variable and largely uncontrollable output patterns become more prevalent, the need for generators that can offer flexibility — including ancillary service — has grown significantly. While ancillary services are becoming increasingly vital for maintaining grid stability, their full commercial value in the market has yet to be recognized. This lack of recognition may hinder investment in resources capable of providing these essential services without system-level interventions.

While operational reliability happens on a sub seconds-to-hours scale, resource adequacy operates on a longer time horizon (seasons-to-years). Planners must ensure that the system not only has enough generation capacity to meet projected demand but also maintains a sufficient reserve margin to account for uncertainties in demand forecasts and supply availability. Particularly important when accounting for this capacity is estimating each resource's ability to generate during hours when demand is the highest (the "peak").

As variable renewable resources become more prevalent, the focus of resource adequacy is increasingly shifting from peak "gross demand" (total demand on the system) to peak "net demand" — defined as total demand minus generation from non-dispatchable sources like renewables. Dispatchable resources, especially those that can flexibly turn on and off within a few hours' notice, are highly valuable to the system during peak demand periods and the "net peak" approach highlights periods when dispatchable supply is needed most (Figure 10). Increasingly, higher penetrations of solar generation have pushed system net peaks into the evening, when solar can no longer generate and contribute to resource adequacy. Though battery storage can help to ameliorate this issue by shifting excess renewable generation from lower net-demand hours to higher net-demand hours, there are limitations to (and costs associated with) this approach.

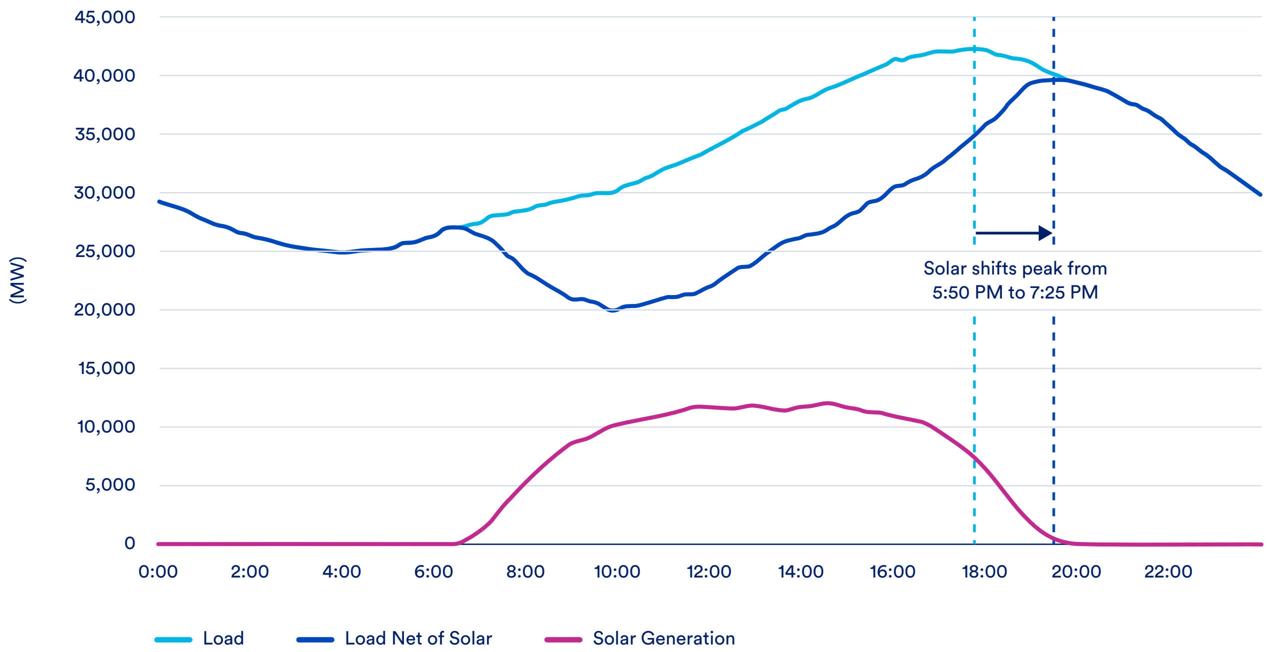
In the U.S. and Europe, rapidly increasing forecasted electricity demand is increasing both peak and net-peak loads due to electrification, onshoring of industry, and growth in data centre demand. For resource adequacy, this has raised concerns regarding dwindling reserve margins and increased risks of outages.

Finally, there needs to be enough transmission and distribution infrastructure to deliver energy to consumers, including when a component of the network may be (expectedly or unexpectedly) out of service.

Figure 10: California load net of solar generation on August 12, 2021

Gross demand (teal line) is defined as the total demand on the system while net demand (dark blue line) is defined as load minus generation from non-dispatchable sources (e.g., solar, wind). Increasingly, the peak net demand (7:25pm in this image) has become more important than the peak gross demand (5:50pm) in reliability planning, as it reflects the period where the system is tightest on dispatchable supply.

Image source: https://www.mass.gov/doc/capacity-resource-accreditation-for-new-englands-clean-energy-transition-report/download



Affordability

Grid planners and operators balance the diverse values offered by different types of resources to meet reliability needs at the lowest possible cost. At the transmission level, this involves deciding whether it is more economically efficient to generate power locally or import it from neighboring regions.[21] At the generator level, this means finding a balance between "baseload" supply — generators that operate reliability and continuously at full capacity to meet the base level of consistent system demand —, "peak" generation — which turns on and off quickly to serve less frequent high demand periods, — and storage resources, which can shift generator output to better align with system demand. Nuclear power plants, for example, can provide a steady stream of power at a low cost per unit of output (variable cost). This makes them prudent choices for baseload generation. However, their low output flexibility and high fixed costs makes them unsuitable for use as peak generators, which may need to ramp several times per day from 0% to 100% output in a matter of minutes. Conversely, gas combustion turbines can turn on and off quickly and have lower fixed costs; however, their inefficiency results in higher costs per unit of energy produced. Therefore, they are typically only used during infrequent peak demand periods.

We discuss the details of power system planning and costs in Power System Decision-making: Planning, Investment, and Operations.

[21] https://www.brattle.com/wp-content/uploads/2021/10/Transmission-Planning-for-the-21st-Century-Proven-Practices-that-Increase-Value-and-Reduce-Costs.pdf

Sustainability

While reliability and affordability have long been the primary goals of electric power system planners and operators, sustainability has emerged as a crucial third element of the trilemma. The portfolio of generators that can satisfy the sustainability criterion, especially with regard to CO_2 emissions, is limited and can be roughly split into two categories: variable renewable generators (e.g. solar and wind) and clean firm generators (e.g. nuclear, gas with CCS, geothermal etc.). This shift has introduced new challenges to maintaining reliability and affordability.

The majority of low-carbon generating resources now being integrated into the system are variable renewable energy (VRE) sources, such as solar and wind. These resources have output that is weather-dependent and cannot be operated dispatchably to meet system demand unless paired with storage, which increases costs. Additionally, VREs do not have the inertia of traditional generators to maintain the grid at a constant frequency and voltage. This increases the importance of resources that can dynamically adjust their output or can store energy from renewable generation in hours of excess supply and dispatch it when demand is high. Finally, VRE output potential is highly dependent on geographic factors, such as solar irradiance or wind quality. Consequently, there is an increasing need for expanded transmission infrastructure to move electricity from generation sites to areas where it is consumed.

Clean firm power refers to power sources that generate electricity on-demand, regardless of the weather or time of day, with minimal emissions. These technologies complement VRE by providing several system-wide benefits:

1. **Reduces overbuilt renewable capacity:** Clean firm power helps balance seasonal and correlated fluctuations in wind and solar output, reducing the need for excessive renewable generation capacity.
2. **Minimizes transmission buildout needs:** Geographically flexible clean firm power reduces reliance on extensive new transmission infrastructure required to connect distant renewable projects.
3. **Replaces fossil fuel backup:** Technologies like advanced nuclear and geothermal can replace fossil fuel backup generation, ensuring reliability during periods of low renewable output.
4. **Accelerates decarbonization:** Clean firm power offers a scalable solution to decarbonize faster, helping mitigate delays from renewable deployment, transmission issues, and slow permitting processes.

Power System Decision-making: Planning, Investment, and Operations

All components of the power system (generation, transmission, and distribution) require vast amounts of capitally intensive infrastructure. This infrastructure is planned, operated, and financed primarily through two models: a vertically integrated system, and a deregulated, markets-based system (Figure 11).

Vertically integrated Systems

The most traditional structure of electricity infrastructure ownership and operation is the vertically integrated system. This system was developed under the assumption that competition within a single region to provide electricity would not be economically efficient, given the large amount of physical infrastructure required to generate, transmit, and distribute electricity (e.g., it would not be efficient to have redundant sets of distribution lines). This is known as a "natural monopoly."

In vertically integrated systems, a single electric utility in each region plans, owns, and controls its territory's generation, transmission, and distribution assets. Some examples of vertically integrated systems today include Florida Power & Light (United States), Iberdrola (Spain), and Électricité de France (France).

In the planning phase of a vertically integrated system, utilities engage in a process known as Integrated Resource Planning (IRP). This involves projecting future demand and supply conditions, assessing how these changes may impact reliability, and developing investment plans for infrastructure to meet established reliability standards at reasonable and just cost (more on that below).

In the operations phase, the utility is responsible for dispatching its generation resources and managing its transmission and distribution grid to effectively meet consumer demand at least cost. This includes optimizing the use of available resources, ensuring a balance between supply and demand, and maintaining the stability of the electrical grid to provide reliable service to customers.

Recovery of both investment and operational costs in vertically integrated systems occurs through consumers' electricity rates. With no competition, however, there is the risk for utilities to charge consumers inefficiently high prices for electricity or provide a lower quality commodity than what consumers would like. To ensure utilities do not take advantage of customers, from both a reliability and affordability perspective, regulators set reliability standards (e.g. National Electricity Reliability Council) and there are utility commissions that review and approve IRPs, monitor utility performance, and approve consumer electricity rates. This system ensures that utilities are operating their grid and making investments in a manner that is the least cost for ratepayers while maintaining an acceptable level of reliability.

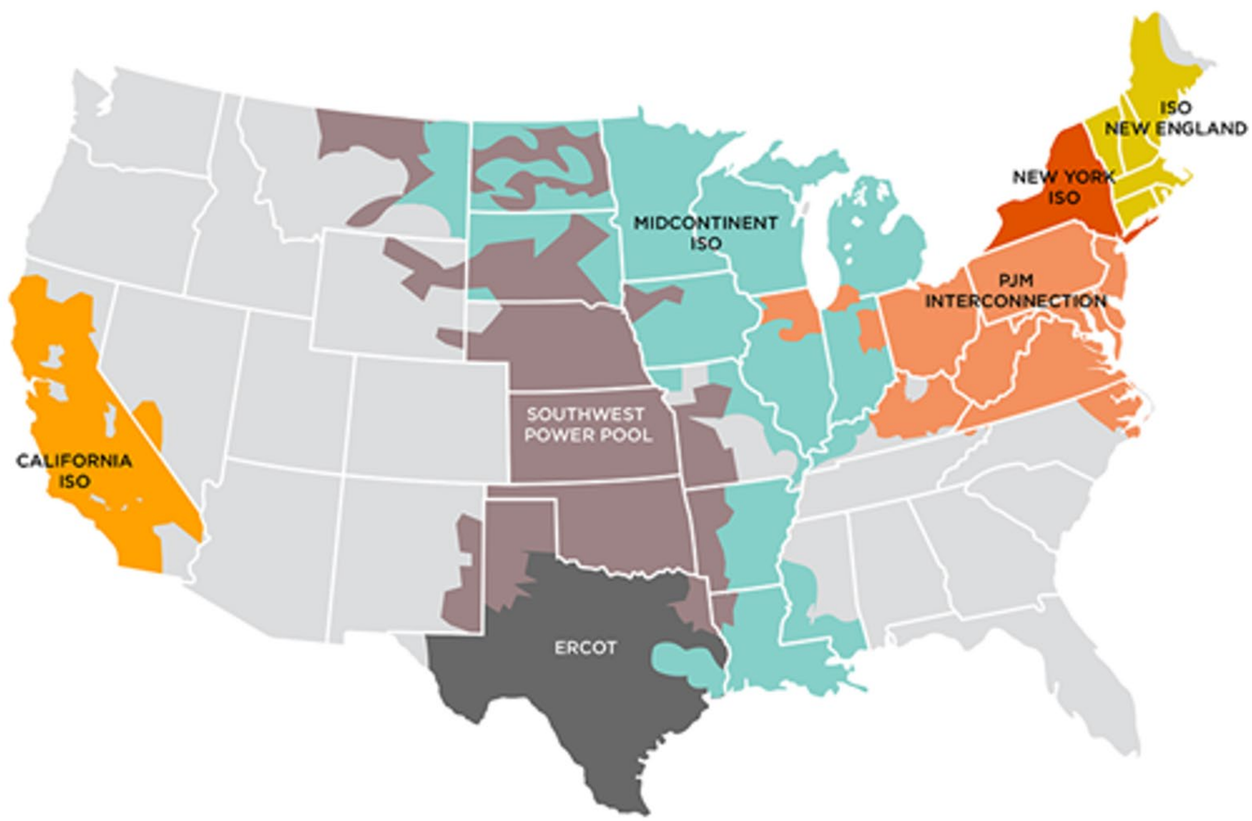
Deregulated Markets

Though many regions still operate under the vertically integrated model, others have moved to a more markets-based approach for generation investment, transmission planning, and power plant dispatching. The wave of neoliberalism during the end of the 20th century saw the introduction of deregulation as a concept in the electricity industry. Deregulation was centred around the theory that the generation component of the utility's vertical structure was not a natural monopoly, and that the introduction of competition would result in more efficient procurement and dispatch of generation resources (Borenstein and Bushnell, 2015; Joskow, 1997).

Figure 11: Deregulated vs. Regulated Markets in the United States

The map shows the regions where a regional transmission organization (RTO) or independent system operator (ISO) operates and runs the electric transmission grid.

Source: https://www.ferc.gov/introductory-guide-electricity-markets-regulated-federal-energy-regulatory-commission



Under a deregulated structure, utilities retain ownership of their transmission and distribution assets and are responsible for operation of their distribution system. However, generation is independently owned and competitively procured and dispatched through regional, independently operated wholesale electricity markets. In effect, any developer could now develop a power plant in these regions, crowd-in investors, interconnect into the wholesale electricity market, and earn energy, ancillary, and in some cases, capacity market revenues.

The entities that operate the transmission grid and oversee these competitive markets are known as Independent System Operators (ISOs) (sometimes Regional Transmission Operators (RTOs)).

The markets that ISOs/RTOs oversee are used to compensate generators for different needs of the system that they serve including:

- **Energy:** a payment for the physical supply of electricity
- **Capacity:** only in some regions, a separate payment for a resource's contribution to resource adequacy (i.e. their ability to generate during peak load)
- **Ancillary Services:** a payment for a generator's real-time contribution to grid balancing and operational reliability

Examples of deregulated, market-based operating regions include the Netherlands, the U.K., NYISO (New York, United States), CAISO (California, United States) and PJM (mid-Atlantic region, United States).

System Costs vs. Project Economics

Policymakers and regulators are tasked to ensure that electricity infrastructure is procured in a way that efficiently meets the needs of the energy trilemma. Whether it is achieved through vertically integrated planning or deregulated market signals, the long-term goal is to provide reliable and resilient electricity supply while minimizing system costs. System costs encompass the total capital and operational expenditures, as well as externalities related to the energy system. Ultimately, these costs are passed on to society, often reflected in electricity rates or tax burdens. Therefore, it is essential for policymakers and regulators to adopt a system cost perspective when evaluating investment options and decarbonization pathways.

In contrast, the goal of independent investors is to ensure bankability at the project level. This means projecting future revenue flows from bilateral agreements (agreements between the produce and a buyer — often a utility — to offtake a particular amount of power) or market price forecasts, and government subsidies to ensure that risk-adjusted revenues exceed the total project development cost to satisfy investors. This calculus does not include how a project may influence the other costs that affect a consumer's final bill, such as system reliability needs, the cost of expanding and maintaining the transmission and distribution networks, and any taxpayer/ratepayer costs from clean energy subsidies.

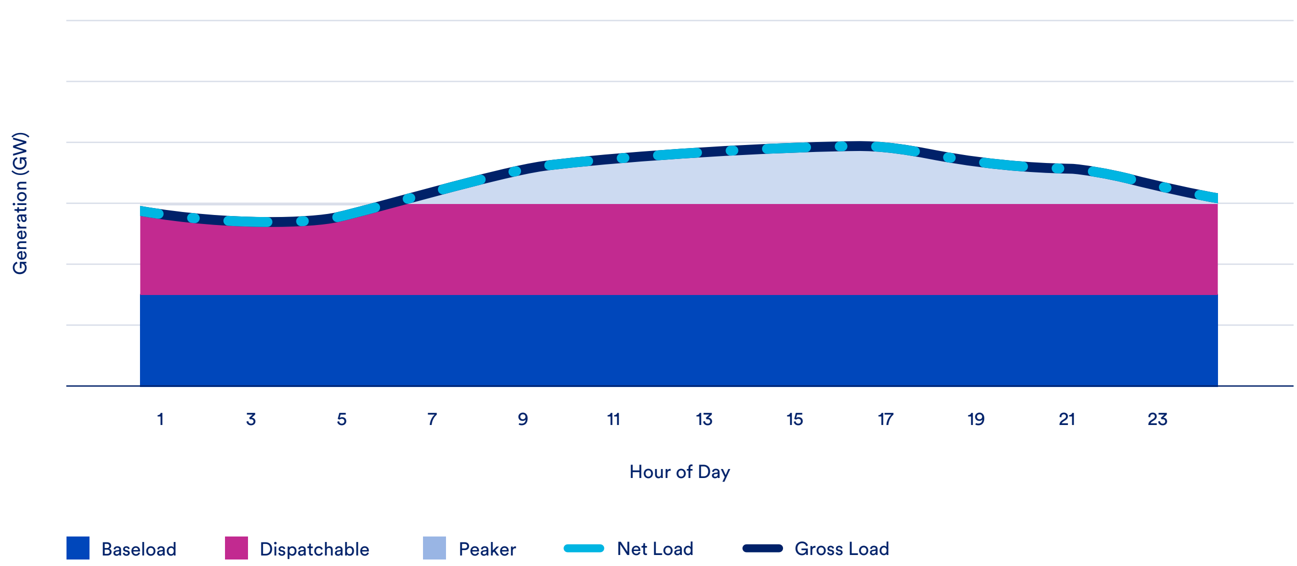
ANNEX B

Evaluating LCOE Appropriateness Under Relevant Scenarios

The hypothetical power system we begin with reflects conditions before the widespread adoption of intermittent renewable resources in the United States and Europe (Figure 12). That is, the system has a low penetration of VRE and its load is primarily served using dispatchable resources — in this example, a low-marginal-cost baseload technology (e.g., coal fired power plant), a dispatchable generation source with high operational costs for adjusting output (e.g., a gas combined cycle plant or clean firm generator), and a flexible peaker plant[22] with high marginal costs (e.g., a gas combustion turbine). Consequently, this hypothetical system reflects many U.S. and European power systems at the time the LCOE metric was originally designed and applied to compare generation technologies.

Figure 12: A power system before the widespread adoption of VRE

Load is mostly served with baseload technologies (e.g., nuclear), dispatchable technologies with mid-tier marginal costs but higher costs to cycle (e.g., a gas combined cycle plant), and peaker plants that are flexible and fast ramping but have a high marginal cost to operate.



[22] "Peaker plants" often refer to very responsive power plants or expensive power plants that are only run during peak demand conditions, or both (e.g. oil combustion turbine).

Throughout the scenarios, we then consider increasing penetrations of lower LCOE resources — here, a solar generation resource and a storage resource that can better align solar output with demand — and analyse whether LCOE of the generation asset is sufficient to capture system cost trade-offs under such conditions. For each scenario, we analyse the system on a representative peak load day, with gross load shape and solar output potential remaining consistent while varying the resource mix and total system demand to reflect the conditions of each scenario.

Scenario 1: No Need for Additional Peak Capacity or Dispatchability

In this scenario, we consider our starting system with a low penetration of variable renewable resources, modest peak load growth, and sufficient dispatchable resources. This reflects power systems that generate with a fleet of dispatchable (usually mostly fossil-fired) resources.[23] To this system, we introduce the availability of a solar generation technology

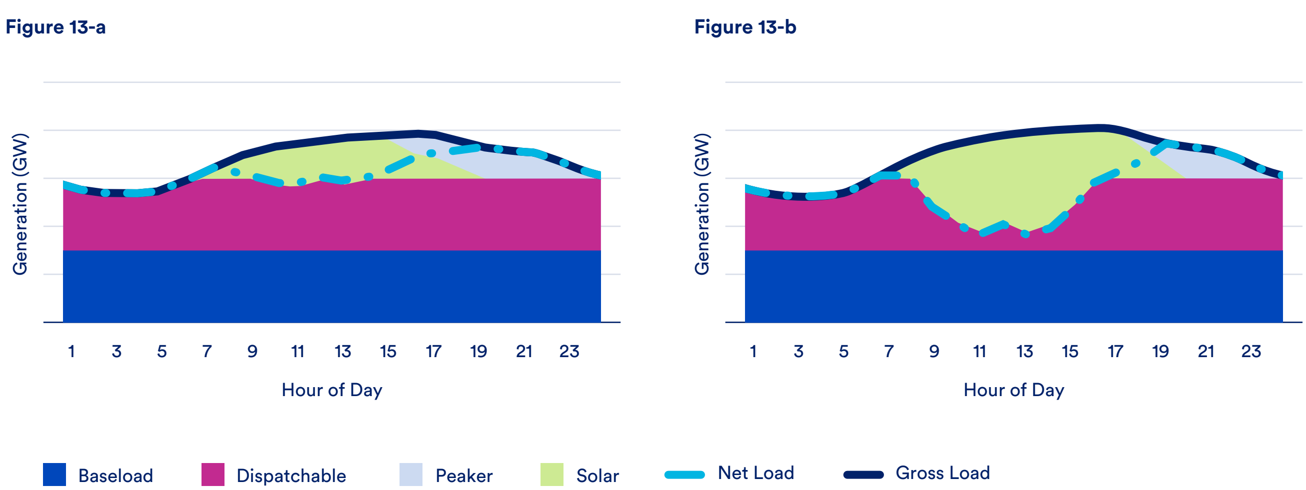
Under these circumstances where the system does not require any increase in peak generation output or dispatchability, the primary objective of a system planner is to reduce the cost of energy and the LCOE of solar may be a relevant metric for that purpose.

If the LCOE of solar is only lower than the variable cost (e.g. fuel costs) of operating a peaker plant (Figure 13a), solar capacity should be installed to displace peaker generation during the day when solar production is at its highest. The peaker will turn back on in the evening once the sun goes down to meet the new net peak demand.

If the LCOE of solar is less than both the variable cost of the peaker *and* of the dispatchable unit (Figure 13b), solar should be built to displace both sources of generation during the day. Both the peaker and dispatchable units will ramp up again in the evening to meet the new net peak.

Figure 13: A system with low peak load growth, low VRE penetration, and little to no firm capacity retirement

The primary motivation of such a system is to reduce overall energy cost (cost to provide a MWh of electricity). Under such system conditions, peak demand occurs in the middle of the day and is served by gas peaker plants. (a) If LCOE of solar is lower than the variable cost of the gas peaker, solar will replace the gas peaker generation in the middle of the day. (b) If the solar LCOE is lower than both the peaker and dispatchable technology, enough will be built to replace both in the middle of the day. Since the primary motivation of a system like this one is to reduce the cost-per-MWh of energy, LCOE could be an appropriate metric if T&D, power plant cycling, and balancing costs are appropriately considered.



23 As an example, Duke Energy Carolina. According to EIA's [Hourly Electric Grid Monitor](), less than 5% of Duke Energy Carolina's generation mix is comprised of VRE, with the remainder being primarily nuclear, coal, natural gas, and hydroelectric.

Note, however, LCOE does not account for all relevant costs and thus may still be insufficient. For example, the system may face additional costs from transmission and distribution upgrades, balancing the variability of solar output, and cycling the dispatchable and peaker plants — costs that will ultimately fall on ratepayers.

Nevertheless, since the primary objective of this type of system is to minimize the cost per MWh of electricity, LCOE can still serve as a useful metric. Even in such scenarios, it is important to refine the LCOE metric to encompass a broader range of costs, along with varying financial and risk assumptions. Better yet, a system analysis can weigh the system costs of various portfolios under different scenarios and sensitivities to understand the lowest cost options.

Scenario 2: Need for Flexibility, but Not Peak Capacity

Now let's build on Scenario 1 and consider a scenario where solar penetration has risen to the level that its generation exceeds the demand previously met by both peaker and dispatchable resources during the daytime. This situation mirrors that of the California Independent System Operator, where high levels of solar integration have highlighted the necessity for enhanced system flexibility — resources that can more effectively align supply with demand. Similarly, the European Commission has acknowledged the growing need for flexibility in increasingly intermittent renewable energy systems.[24]

In this scenario, there are three primary options. The first is to ramp down the baseload generator. This may not be ideal for two reasons. If the baseload generator has a lower cost of generating electricity than the LCOE of a new solar facility, then ramping down its output would be uneconomic. Also, if the baseload power plant is designed to be run at a constant level, like older steam cycle natural gas power plants or coal plants, turning them off and on quickly can dramatically increase costs and potentially shorten the operational lifespan of the generator.[25]

To avoid displacing baseload generation, the second option is to curtail some of the solar generation (Figure 14a). This means that only a fraction of the energy that solar produces is consumed, effectively raising the LCOE of solar power by reducing the total production that its costs are spread over. As a quick example, consider a situation where roughly 20% of the solar output is curtailed to avoid the costs associated with turning power plants on and off. We calculate the effective LCOE (*LCOEe*), or the levelized cost of energy that is consumed (and not curtailed), as:

$$LCOE_e = \frac{\frac{\text{Total Cost}}{\text{Total Production}}}{\frac{\text{Amount of Uncurtailed Production}}{\text{Total Production}}} = \frac{LCOE}{80\%} = 1.25 * LCOE$$

The third option is to consider the addition of battery storage, which could shift some of the excess solar output to later hours in the day. As illustrated in Figure 14b, this would provide much more value to the system than solar alone. By incorporating battery storage, the sys tem can reduce curtailment during high solar production in the middle of the day while also displacing (expensive) peaker generation during the evening hours when demand rises.[26]

As demonstrated, using only the LCOE of solar in comparison with other resource costs in isolation fails to capture the true costs to the system when additional flexibility is required. While solar may appear cheaper than dispatchable and peaker resources, it's crucial to account for the added expenses associated with either curtailing excess solar output or investing in battery storage to shift solar generation to later in the evening. Neither of these costs is reflected in the LCOE metric.

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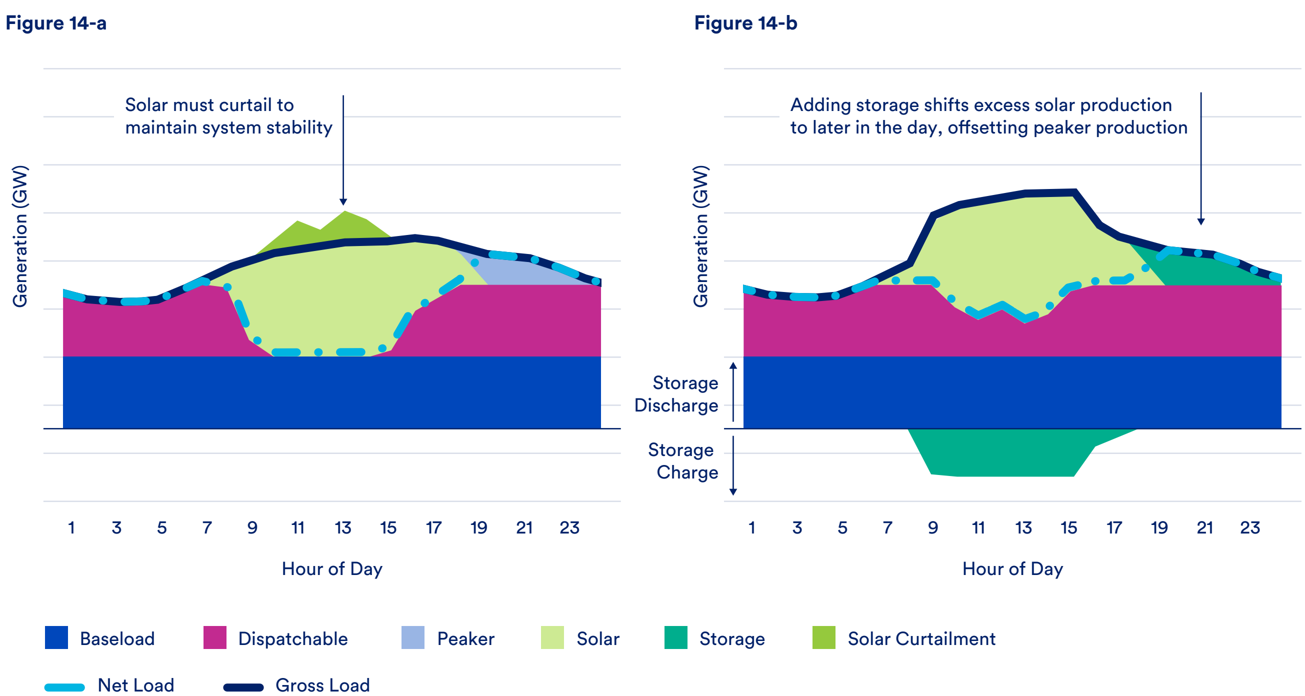
24 https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32023H0320%2801%29&qid=1679302898964

25 https://www.nrel.gov/docs/fy12osti/55433.pdf

26 For example, the U.S. National Renewable Energy Laboratory documents in their paper How the U.S. Power Grid Kept the Lights on in Summer 2024 (see PDF Figure 4): https://www.nrel.gov/docs/fy25osti/91517.pdf

Figure 14: A system with low peak growth, high VRE penetration, and low firm capacity retirement

With little flexibility remaining on the system in the middle of the day, solar must be curtailed to maintain system stability. (a) Adding more solar to the system will not alleviate and, in fact, worsen the flexibility challenge. (b) Adding a battery resource will shift excess solar output to later in the day, reducing solar curtailment and replacing expensive peaker generation. Neither the cost of solar curtailment, nor the need for additional storage resources, is reflected in the original solar LCOE.



Scenario 3: Need for Additional Peak Capacity

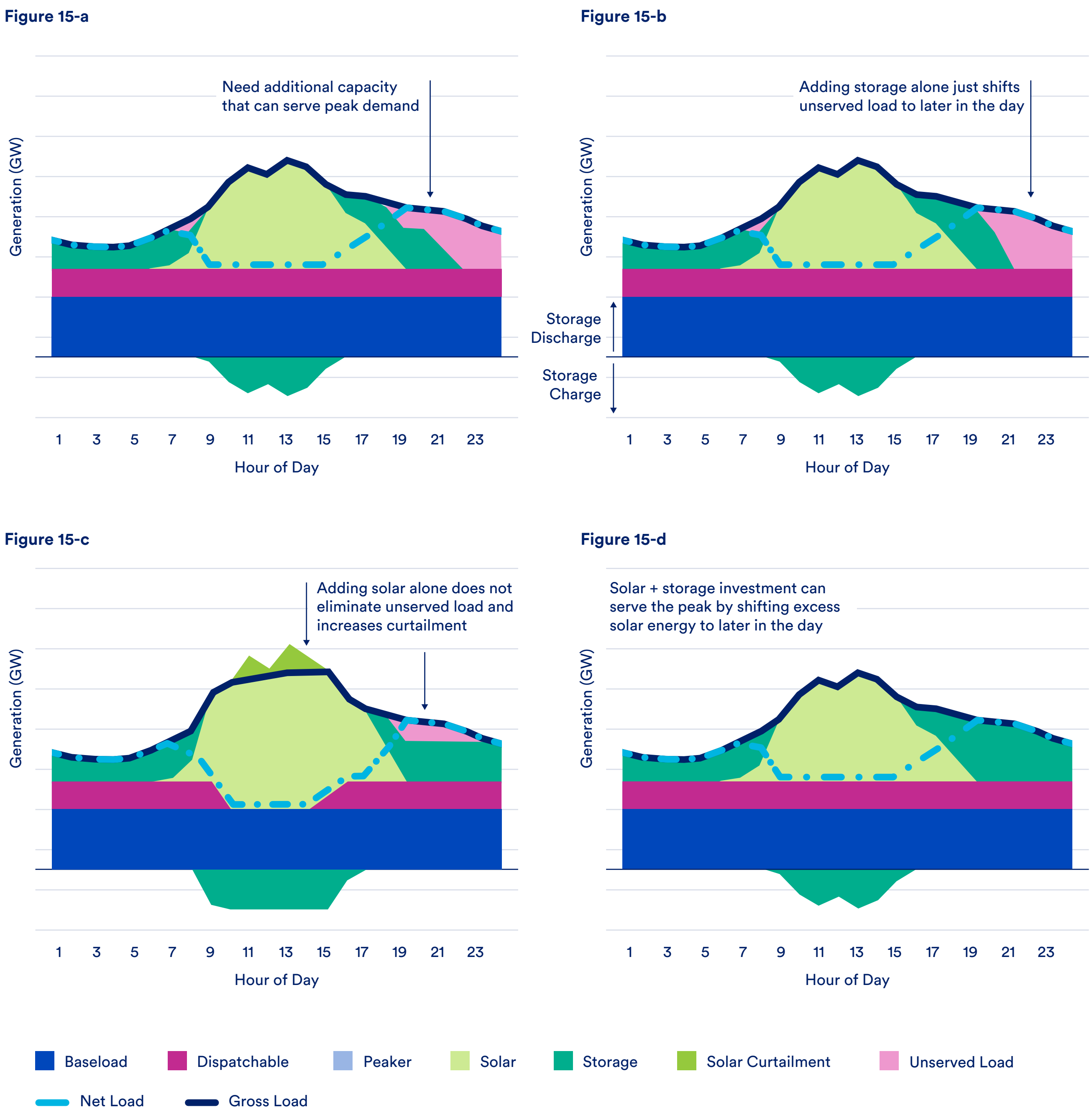
Building on Scenario 2, we introduce the retirement of the peaker and dispatchable supply (e.g. due to old age or reduced revenues from increased penetration of renewable generation). Here, the primary system need is for additional capacity to meet peak demand (Figure 15a).

Unlike Scenario 2, more battery capacity alone cannot be added to shift solar output from the middle of the day to evening hour, as nearly all the solar generation is being consumed when it is produced (Figure 15b). Adding more solar generation on its own also does not ameliorate the situation either, as there is insufficient system flexibility to shift the excess generation to the evening peak, and the excess solar ultimately gets curtailed (Figure 15c). Therefore, the LCOE of solar or the cost of storage alone are inadequate metrics for understanding how to best meet system needs. Considering the cost of hybrid resources, discussed below, can help make more informed decisions.

To address this problem, a system must invest in resources that can not only replace the generation deficit caused by the retirement of dispatchable capacity but also provide sufficient dispatchability to align generation with demand. One option is a combined solar and storage solution, which can produce additional energy during the middle of the day and shift some of that excess generation to meet the evening peak hours (Figure 15d). In this case, the combined cost of the solar and storage resource needs to be considered. Lazard's recent LCOE report attempts to provide such a cost estimate, with solar and storage resource combined LCOE being reported to be above $100/MWh in California and PJM. Other options would be a new gas plant, nuclear plant, geothermal plant, or other dispatchable technology.

Figure 15: A system with high VRE penetration, high levels of peak capacity retirement, and low load growth

(a) In this system, there is need for additional capacity to meet peak demand. (b) Investing in storage alone is insufficient, as there is not enough excess generation at other parts of the day to shift to peak demand hours. (c) Investing in solar alone will also be insufficient, as the timing of solar generation is out of sync with net peak demand, resulting in large amounts of curtailment. (d) A potential solution in this case would be a solar + storage investment, which would allow for both more generation overall and the flexibility to align generation with peak demand.



Scenario 4: Long-Term Economy-Wide Decarbonization

Finally, we consider a scenario focused on economy-wide decarbonization in the long term. This scenario presents significant challenges and opportunities for the energy system as it seeks to balance decarbonization with rising electricity demand. Deep decarbonization scenarios are much more complex than our hypothetical example can consider, and the LCOE metric is insufficient for determining what resources can best minimize system costs for customers.

A decarbonized economy requires significant electricity load growth from electrification of other sectors —including buildings, transportation, and industrial. Additional demand growth from data centres may further exacerbate this challenge. For instance, demand from data centres, which is likely to be high capacity factor, in Europe is expected to nearly triple, from about 62 TWh to more than 150 TWh, by 2030.[27]

To meet this demand with clean resources, complex analysis is needed to understand the cost trade-offs of different infrastructure portfolios that vary generation, storage, transmission, load flexibility, and distribution to meet annual electricity loads.

Sensitivities must consider the uncertainty of daily, weekly, and seasonal generation patterns of weather-based resources and the potential flexibility of electrified load (e.g. electric vehicle charging). Reliability and resilience must also be evaluated, such as the system's inertia levels and the resiliency of systems under various outage and extreme weather scenarios. System resilience to supply chain disruptions and commodity price volatility would also be necessary.

Last, any large-scale build out of infrastructure needs to be evaluated against land and other environmental impacts, supply chain, and other potential constraints. Even at the low penetrations today, solar and wind technologies are meeting land-use challenges in regions that are both supportive and not supportive of climate policy.[28] Infrastructure buildout rates are also challenging the speed at which resources can be developed.[29] Labor supply may also become a challenge in deep decarbonization scenarios.[30]

Most credible analyses of deep decarbonization scenarios suggest that a portfolio of solar, wind, storage and clean firm resources result in the lowest cost and most reliable decarbonized power system.[31] Similarly, analysis of storage costs suggest that long-term storage is unlikely to reduce in cost sufficiently to offset the need for clean firm resources.[32] When examining a system modelling study, readers must investigate whether it is investigating full or partial decarbonization, the sensitivities it examines, the temporal and geographical resolution of the modelling, assumptions about transmission constraints and buildout rates, and other factors, as they will all impact the quality of the results.

Thus, it is very clear the use of LCOE on its own is not appropriate to make long-term power system decisions or assess the potential for a technology to reduce customer costs under deep decarbonization scenarios.

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28 R. Nilson, et al. "Halfway up the ladder: Developer practices and perspectives on community engagement for utility-scale renewable energy in the United States." Energy Research & Social Science 2024, 117. DOI: 10.1016/j.erss.2024.103706.

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31 https://www.sciencedirect.com/science/article/pii/S2542435118303866

32 https://www.nature.com/articles/s41560-021-00796-8

Figure 16: Summary figure of a modelling exercise that evaluated the average system costs of different electricity system portfolios, limiting the availability of clean firm resources in half of the scenarios[32]