Total Levelized Generation Costs in the Chilean Power System

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Abstract

The different electricity generation technologies are usually compared using the Levelized Cost of Electricity (LCOE), which summarizes fixed and variable costs into a single cost metric per unit of energy generated. The LCOE reflects the price required to cover investment and operating costs; however, it does not account for the costs arising from irregular and non-manageable generation profiles, particularly for wind and solar photovoltaic power plants, and therefore does not represent the total system cost.

This study reviews the state of the art in improvements to the LCOE, including the Levelized Full System Cost of Electricity (LFSCOE). The LFSCOE is defined as the levelized cost of providing electricity through a given generation technology, assuming a market supplied exclusively by that source, plus the storage systems required to satisfy demand at all times. Methodologically, the LFSCOE is the opposite extreme of the LCOE; while the latter assumes no obligation to balance the market or satisfy demand, the LFSCOE assumes maximum balancing and supply obligations. The LFSCOE cannot be interpreted as the system's levelized cost considering its current technological composition; however, its virtue lies in enabling a straightforward comparison of the competitiveness of existing technologies.

For the Chilean electricity system, the results show that the LFSCOE of hydroelectric technology ranges from 78–146 USD/MWh depending on the investment scenario, while wind and solar photovoltaic reach 145 and 140 USD/MWh, respectively. The results show that only under the most unfavorable hydroelectric investment scenarios do wind and solar photovoltaic technologies become competitive.

Keywords: LCOE, LFSCOE, renewable energy, hydroelectric, solar photovoltaic, wind, energy storage, Chile

1. Introduction

In long-term electric power system planning and in the formulation of energy policies, the Levelized Cost of Electricity (LCOE) is commonly used to assess the competitiveness of different generation technologies, in terms of the fixed and variable costs of generating electricity per unit of energy produced. This is obtained by dividing the present value of total generation costs, yielding a final value expressed in dollars per unit of energy generated. The main advantage of the LCOE is its simple formulation, which provides a straightforward cost metric useful for comparing different generation technologies. For example, Lazard (2025) reports that in the United States, the LCOE of wind power plants ranges from 37–86 USD/MWh, between 38 and 78 USD/MWh for solar photovoltaic plants, between 71 and 173 USD/MWh for coal-fired units, and between 48 and 107 USD/MWh for combined-cycle gas plants. Meanwhile, the LCOE of large hydroelectric plants ranges from 40–147 USD/MWh, according to IRENA (2024).

The widespread use of the LCOE has led to the common perception that the technology with the lowest LCOE is necessarily the most cost-effective option for expanding an electricity system. However, electricity differs from most commodities because its economic value depends not only on production cost but also on the time, location, and reliability of delivery. Consequently, technologies with similar LCOE may provide substantially different value to the power system depending on their operational characteristics and their contribution to system reliability Hirth (2013); Borenstein (2012).

This distinction has become increasingly important with the rapid deployment of Variable Renewable Energy (VRE) technologies, particularly wind and solar photovoltaic generation. Unlike conventional dispatchable generators, VRE output depends on meteorological conditions and cannot be controlled according to system demand. As VRE penetration increases,

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additional investments become necessary to maintain the continuous balance between electricity supply and demand, including storage systems, transmission reinforcement, reserve capacity, balancing services, and other flexibility resources. Consequently, the total cost of integrating VRE into the power system exceeds the direct generation cost captured by the conventional LCOE. For example, Agora Energiewende (2015) estimate that integration costs in Germany reach approximately 9 EUR/MWh for solar photovoltaic generation and 13 EUR/MWh for wind generation, increasing as renewable penetration grows. Similar conclusions regarding the declining economic value of VRE at high penetration levels have been reported by Mills and Wiser (2012).

Joskow (2011) was the first to point out that the LCOE is not a good comparison tool, as it is only concerned with the direct costs of electricity generation, and ignores the costs associated with intermittency, an essential point in electricity markets, where the balance between generation and demand must be maintained at all times. Emblemsvåg (2025) goes further, arguing that despite reputable agencies acknowledging some problems with the LCOE, they do not improve their calculations and do not report the costs that the incorporation of VRE will impose on the system. In his study, the same author describes new methodologies that improve the LCOE in order to incorporate VRE integration costs. (Schernikau et al., 2022) introduce the concept of the Full Cost of Electricity (FCOE), which should consider, among others, the costs of construction, fuel, operation and maintenance, transmission, storage, backup, and emissions. The OECD Nuclear Energy Agency has reached similar conclusions, emphasizing that transmission expansion, storage, backup capacity, and other system-level expenditures become increasingly important as renewable penetration increases OECD Nuclear Energy Agency (2019).

Ueckerdt et al. (2013) propose calculating the system LCOE of an intermittent source as the sum of generation costs (the traditional LCOE) plus integration costs: balancing costs, grid costs, and profile generation costs. Grid balancing costs include the costs of ensuring the balance between generation and demand, taking into account the uncertainty of intermittent generation. Grid costs are associated with the additional investments needed to integrate renewable plants. Profile costs include all costs related to matching supply to demand if market conditions can be forecast with some precision. According to the authors, unlike the conventional LCOE, the system LCOE of renewable sources depends heavily on their market share. In the case of wind generation, with penetration levels of 40% of total generation and a generation cost of 60 USD/MWh, the system LCOE exceeds 100 USD/MWh. For solar photovoltaic generation with a generation cost of 120 USD/MWh and a penetration of 25% of total generation, the system LCOE reaches 220 USD/MWh. Reichenberg et al. (2018) show that in Europe, for penetration levels of 50%, the systemic LCOE of VRE is around 80 USD/MWh and increases almost linearly for penetration levels up to 80%, at rates of 6 USD/MWh for each additional 10% of VRE penetration.

Marín-Cano and Mejía-Giraldo (2018) propose the Levelized Avoided Cost of Electricity (LACE) as a complementary metric to the LCOE for evaluating new generation projects. LACE is defined as the reduction in system operating costs produced by a new project per unit of electricity generated, and is estimated by comparing system operation with and without the project using a Security-Constrained Optimal Power Flow (SCOPF) under multiple operating scenarios. Unlike the LCOE, LACE captures operational benefits such as the displacement of expensive generation, congestion relief, and improvements in system security. Applying the methodology to the Colombian power system, the authors find that geothermal generation exhibits the highest LACE and net benefit among the technologies evaluated.

While the system LCOE described in the previous paragraph is a fairly complete and precise methodology, its application is more complex, as it requires more detailed modeling of the electric power system considering, among other things, inertia constraints, characteristics of existing thermoelectric plants, and reserve requirements. Instead, Idel (2022) proposes calculating the Levelized Full System Cost of Electricity (LFSCOE). The LFSCOE is defined as the cost of providing electricity to total demand using only a given technology, plus the storage systems needed to maintain the balance between generation and demand at all times. In simple terms, the LFSCOE of a technology is calculated by optimizing the investment in installed generation and storage capacity over a planning horizon, meeting hourly demand; an equivalent present value cost is then calculated by averaging over total demand served. The author reports that the LFSCOE of wind technology in Texas is 291 USD/MWh and in Germany 504 USD/MWh, while for solar photovoltaic technology it is 413 USD/MWh in Texas and 1,548 USD/MWh in Germany.

Chile occupies a singular position in the global energy transition. The country holds some of the most exceptional renewable resources on Earth: the Atacama Desert records solar irradiation levels exceeding 2,500 kWh/m^2/year—among the highest globally—while Patagonia offers world-class wind potential, making Chile one of the countries with the highest renewable resource potential worldwide. These natural endowments have underpinned an ambitious energy policy agenda. Chile has committed to achieving 70% renewable electricity by 2030 and carbon neutrality by 2050, placing it among the most ambitious energy-transition economies in the developing world.

The pace of this transition has been remarkable. In 2025, 63% of Chile's electricity generation came from renewable sources, led by solar photovoltaic (23%), hydropower (24%), and wind energy (14%), bringing the country within reach of its 2030 renewable electricity target five years ahead of schedule. The Long-Term Energy Planning (Ministerio de Energía, 2025) and the Transmission Expansion Proposal (Coordinador Eléctrico Nacional, 2025) project that virtually all new generation capacity over the next two decades will consist of VRE technologies and battery storage, with no new conventional dispatchable plants. This strategy represents a multi-billion-dollar investment programme whose costs will ultimately be passed on to final electricity consumers. It has also entailed the retirement of a significant number of coal-fired power plants, with further early retirements planned. Yet the transition is not without warning signs. Approximately 20% of VRE generation was curtailed in 2024—four to more than ten times the curtailment rates of 1.5–5% reported in Spain, Germany, and the United Kingdom, despite operating at comparable VRE penetration levels. These curtailment levels suggest that system integration costs are already becoming significant.

Beyond increasing integration costs, the rapid deployment of inverter-based renewable generation has also introduced new operational challenges. These became evident during the nationwide blackout of February 25, 2025. Although the initiating event was the disconnection of a 500-kV transmission line, subsequent technical analyses identified the low inertia of the power system, together with the limited availability of grid-forming resources in a system dominated by inverter-based generation, among the factors that contributed to the propagation of the disturbance and complicated system restoration Muñoz (2025); Universidad de Chile (2025). The event underscored that a highly renewable electricity system requires not only sufficient generation capacity but also adequate system-strength services, including inertia, frequency response, and voltage support.

These financial and operational challenges reinforce the need for more comprehensive metrics to guide investment and policy decisions. Despite the scale of the investments involved, such decisions continue to rely primarily on the Levelized Cost of Energy (LCOE), a metric that, as this study demonstrates, can underestimate the full system cost of VRE technologies by a factor of three to five. To the authors' knowledge, no comprehensive assessment has been published evaluating the overall cost-effectiveness of Chile's energy transition strategy, nor its contribution toward the global climate objectives established by the IPCC. Against this background, understanding the full-system costs of alternative generation technologies becomes increasingly important as Chile advances along its decarbonisation pathway. It is in this context that this paper estimates the LFSCOE of wind, solar photovoltaic, and run-of-river hydroelectric technologies in the Chilean electricity system, providing an analytical framework to support cost-efficient decarbonisation while ensuring that the costs ultimately borne by electricity consumers are properly accounted for.

The paper is organized as follows. Section 2 introduces the conventional Levelized Cost of Electricity (LCOE). Section 3 presents the Levelized Full System Cost of Electricity (LFSCOE) methodology. Section 4 describes the assumptions adopted in the simulations. Section 5 presents the results, and Section 6 concludes the paper.

2. Levelized Cost of Electricity

The conventional Levelized Cost of Electricity (LCOE) is used in this work as the reference metric against which the proposed methodology is compared. It is defined as the ratio between the discounted lifetime costs of a generating facility and the discounted electricity produced over the same period (Kabeyi and Olanrewaju, 2023)

$$LCOE = \frac{\sum_{t=0}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=0}^{n} \frac{E_t}{(1+r)^t}}, \tag{1}$$

where I_t denotes investment expenditures, M_t operation and maintenance costs, F_t fuel costs, E_t the electricity generated during year t, r the discount rate, and n the project lifetime.

For technologies whose annual energy production changes over time because of equipment degradation or other performance effects, the LCOE may be expressed as

$$LCOE = \frac{CAPEX + \sum_{t=1}^{n} \frac{OPEX_t}{(1+WACC_{\text{nom}})^t}}{\sum_{t=1}^{n} \frac{E_0(1-d)^t}{(1+WACC_{\text{real}})^t}}, \tag{2}$$

where $CAPEX$ is the initial investment, $OPEX_t$ represents annual operating expenditures, E_0 is the initial annual electricity production, d is the annual degradation rate, and $WACC$ denotes the weighted average cost of capital.

Equations (1) and (2) consider only the direct costs associated with electricity generation. Consequently, costs associated with balancing, reserve provision, transmission expansion, storage, and other system services required to integrate generation into the power system are excluded. These omitted costs motivate the development of broader cost metrics, including the Levelized Full System Cost of Electricity (LFSCOE), presented in the following section.

3. Levelized Full System Cost Electricity

The first step consists of running an investment and minimum-cost operation optimization model for an annual horizon with hourly stages, a 30-year horizon, and a discount rate of 7%. The optimization does not consider the existing technological composition of the electricity system, so it is assumed that supply comes exclusively from the electricity source whose impact is being measured, plus the storage systems needed to supply total demand at all times. The model follows the formulation proposed by Idel (2022) for intermittent, non-dispatchable sources, in which wind, solar photovoltaic, and run-of-river hydropower are all represented by an exogenous hourly capacity factor rather than a controllable dispatch variable.

Let rp denote the installed generation capacity of the renewable technology under evaluation and sp the installed power capacity of the storage system (both decision variables of the optimization problem). Let x_t be the storage level at the beginning of hour t, $\text{Ren}_t \in [0, 1]$ the hourly capacity factor of the renewable source, and d_t the hourly demand, for $t = 1, \ldots, H$ (with $H = 8760$ for a full year). The levelized fixed-cost annuity of technology y, with y = Ren for the renewable generation technology and y = Storage for the storage system, over the 30-year evaluation horizon is

$$fc_y = \frac{cc_y}{2} + \frac{cc_y}{2}\beta + \sum_{u=2}^{29} \beta^u \, omc_y, \tag{3}$$

where cc_y is the overnight capital cost, omc_y is the fixed operation and maintenance cost, and $\beta = 1/(1+r)$ is the annual discount factor, with r the discount rate. For each technology, the optimal installed capacities (rp^*, sp^*) and the storage trajectory x_t^* solve

$$\min_{rp,\, sp,\, x} \; rp \cdot fc_{\text{Ren}} + sp \cdot fc_{\text{Storage}} \tag{4}$$

subject to

$$\begin{aligned}
0 \le x_{t+1} &\le x_t + \text{Ren}_t \cdot rp - d_t, && \text{for all } t, && (5)\\
-sp \le x_{t+1} - x_t &\le sp, && \text{for all } t, && (6)\\
S_{\text{security}} \le x_t &\le sp \cdot \rho_{sf}, && \text{for all } t, && (7)\\
x_1 &\le x_{H+1}. && && (8)
\end{aligned}$$

Constraint (5) ensures that demand is met in every hour while allowing free curtailment of generation in excess of demand and storage capacity; constraint (6) limits the hourly charge and discharge of the storage system to its installed power capacity sp; constraint (7) keeps the storage level between a minimum security level S_{security} (set to zero in this study, as no security backup is assumed) and the maximum usable level, determined by the storage factor ρ_{sf} (the ratio of usable energy capacity to power capacity); and constraint (8) requires the storage level at the end of the horizon to be at least as large as at the beginning, so that technologies are compared on a level playing field.

Once the optimal solution $z^* = rp^* \cdot fc_{\text{Ren}} + sp^* \cdot fc_{\text{Storage}}$ is obtained, the LFSCOE is calculated as the levelized present value of this minimum cost over the entire evaluation horizon, according to the expression:

$$\text{LFSCOE} = \frac{z^*}{\displaystyle\sum_t \frac{d_t}{(1+r)^t}}. \tag{9}$$

4. Assumptions

The assumptions used in the simulations are shown in Table 1. The CAPEX and OPEX values are the reference values reported in Comisión Nacional de Energía (2025). For run-of-river hydropower, the CNE-reported value of USD 4,880/kW does not appear to be representative of an average cost. Indeed, IRENA (2024) reports for hydroelectric plants in the 551–600 MW range—a size similar to the largest plants installed in Chile—an average of USD 2,084/kW, and for the 95th percentile of the highest values, a cost of USD 2,945/kW. Accordingly, in this study, for hydroelectric technology, an additional scenario of USD 2,500/kW has been considered, somewhat more pessimistic than the IRENA average, and another scenario of USD 3,000/kW, similar to the IRENA 95th percentile.

Scenario	CAPEX USD/kW	OPEX USD/kW-year
Run-of-River 1 – IRENA avg.	2500	50
Run-of-River 2 – IRENA p95%	3000	60
Run-of-River 3 – CNE	4880	98
Wind	1483	30
Solar PV	809	16
Storage system (4 hours)	814	16

Table 1: Evaluation assumptions.

Equipment manufacturers normally restrict the discharge of storage systems so as not to affect their useful life and to maintain equipment warranties. This value is usually between 80% and 90%; for the purposes of this study, a maximum discharge of 85% has been assumed.

Table 2 shows the capacity factors of the three technologies, obtained from the hourly statistics published by the Coordinador Eléctrico Nacional (2024). Hydrological conditions in 2024 were drier than average, with a hydrological exceedance of approximately 64%, indicating that 64% of the historical hydrological record experienced higher inflows than those observed in 2024.

	Wind	Solar	Run-of-River
Average	0.34	0.33	0.61
p10%	0.13	0.00	0.43
p50%	0.34	0.29	0.62
p90%	0.58	0.78	0.77

Table 2: Hourly statistics of plant capacity factors.

5. Results

Table 3 shows the results obtained for the LFSCOE of the renewable technologies and compares them with the traditional LCOE. In all technologies, the LFSCOE is higher than the LCOE. The highest LFSCOE values correspond to VRE technologies; for wind, the LFSCOE is approximately 3 times higher than the LCOE, and it is almost 5 times higher for solar photovoltaic.

Comparing the LCOE of the technologies would lead to the conclusion that VRE technologies are more competitive than hydroelectricity. However, this conclusion is reversed when considering the LFSCOE, which accounts for the intermittency of renewable sources and better represents the system cost. It can be seen that only in the Run-of-River 3 – CNE scenario, the most unfavorable for hydroelectric investment, do VRE technologies begin to be competitive.

The following figure presents a sensitivity analysis of the maximum allowable storage depth of discharge, varying it from 80% to 100%. It can be seen that the most affected technology when raising the maximum discharge level is solar photo-

Scenario	LCOE	LFSCOE
Run-of-River 1 – IRENA avg.	47	78
Run-of-River 2 – IRENA p95%	56	93
Run-of-River 3 – CNE	91	146
Wind	50	145
Solar PV	28	140

Table 3: Comparison of LCOE and LFSCOE for renewable technologies (in USD/MWh). Values excluding taxes.

voltaic, which is to be expected, since during nighttime hours, storage systems must cover total system consumption.

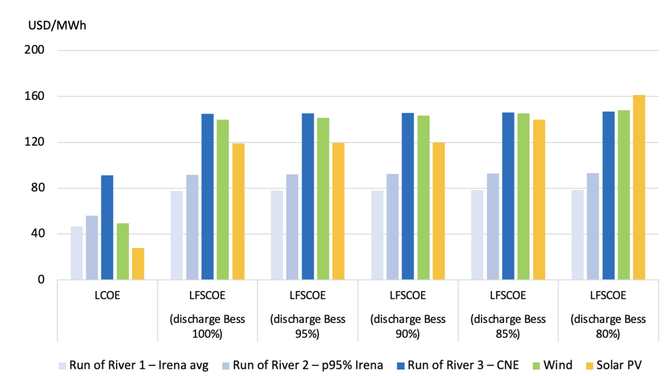

Figure 1: LFSCOE according to different maximum discharge rates in storage systems.

6. Conclusions

Due to its simplicity, the LCOE has frequently been used to justify energy policies in favor of certain technologies, or to promote the decarbonization of electricity generation. However, criticisms of the LCOE are not scarce.

As this study shows, the LCOE does not capture the cost of intermittency of renewable technologies that cannot control the dispatch of their generation. Comparing technologies using the LCOE criterion may therefore lead to investment decisions and energy policies that deviate from the social optimum.

A comparison of the LCOE across different technologies, whether renewable or thermoelectric, tends to overestimate the economic efficiency of VRE technologies. Simply put, the fact that the LCOE of VRE is lower than that of conventional plants—whether hydroelectric or thermoelectric—does not imply that their implementation is economically efficient or competitive for the system.

This study has evaluated a new cost metric that partially addresses the deficiency of the LCOE, by incorporating the costs arising from the intermittency of energy sources. The LFSCOE of a technology thus reflects the system cost of supplying all demand using only that technology, plus the backup needed in storage systems to maintain the balance between generation and demand at all times. In this way, the LFSCOE provides a direct signal of the cost-effectiveness of a technology, enabling easy comparison between them. However, the LFSCOE should not be confused with the system LCOE, which instead represents the marginal cost of adding variable renewable generation to an existing electricity system, taking into account the prevailing generation mix. The proposed metric has been applied to the Chilean electricity system, which has already achieved renewable energy penetration levels comparable to those targeted by the most ambitious energy transition policies in Europe's wealthiest jurisdictions.

The results show that, when considering the LFSCOE, hydroelectricity is more competitive than VRE options, and only in scenarios of high investment costs do VRE technologies approach hydroelectricity. These findings are consistent with those of Galetovic et al. (2012) that already showed that hydroelectric expansion—estimated at around 15 GW—would be the most efficient option in the Chilean electricity system. The potential reported by these authors is similar to the 12 GW reported by the Ministerio de Energía (2021); however, this potential is reduced to less than 2 GW due to the activation of social, territorial, and environmental constraints, which would explain why, in the Long-Term Energy Planning Ministerio de Energía (2025) and in the Transmission Expansion Proposal of the National Electricity Coordinator Coordinador Eléctrico Nacional (2025), the expansion of the electricity system over the next 20 years is based primarily on VRE technologies and storage systems, while virtually no new hydroelectric plants appear. These findings are also highly relevant for other countries with substantial undeveloped hydropower potential, as they suggest that fully accounting for the system costs associated with renewable intermittency may significantly improve the relative competitiveness of hydroelectric generation.

Overall, the results suggest that it is advisable for planning studies developed by the authorities to report the system's levelized cost of technological expansion alternatives, with and without restrictions beyond those that are purely technical. In this way, customers—who ultimately pay for the electricity service—will be able to compare the costs of expansion options and weigh them against the costs implied by restrictions that are not of a technical nature.

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